Wind energy in offshore grids

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Wind energy in offshore grids

by
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Summary

This cumulative PhD thesis deals with wind integration in offshore grids from an economic point of view. It is composed of a generic part and eight papers. As the topic has mostly been analysed with a focus on topology and technical issues until now, market-operational questions in offshore grids and investment implications under different regulatory frameworks are a hitherto underrepresented research field. They are addressed by this thesis.

Offshore grids between several countries combine the absorption of wind energy with international power trading. However, the inclusion into an offshore grid affects the economics of an offshore wind park. It is shown that the spot market income is lower if an offshore wind farm is placed in an interconnector and subject to nodal pricing instead of having a national affiliation. Moreover, congestion in the interconnector can prevent the wind farm from correcting its wind forecast errors in a specific onshore balancing group. An analytical approach with a transmission system operator and a wind farm as stakeholders illustrates resulting incentives for strategic behaviour. Depending on the regulatory regime, they may be inclined to announce more or less generation than expected at the closure of the day-ahead spot market. This can lead to a suboptimal utilisation of the infrastructure and associated socio-economic losses. These and possibly undesired reallocative effects between the parties can be avoided if the regulatory regime is adjusted to reflect special characteristics of offshore grids. With an operational real options approach, it is furthermore illustrated how different support schemes and connections to additional countries affect the investment case of an offshore wind farm and the income of the transmission system operator. The investment framework has also been addressed with a policy study about possible combinations of support schemes and international cooperation mechanisms between countries to achieve their renewable electricity generation targets. In the near future, tendering of joint projects is a feasible solution.

Case studies on the Kriegers Flak offshore hub in the Baltic Sea and on the question of offshore storage, applying the WILMAR Joint Market Model, complement these analyses. The study on Kriegers Flak shows that embedded wind generation approximately halves congestion rents. While building and operating an adiabatic cavern air energy storage appears technically feasible, several reasons are explained why this is inferior to an onshore solution from an electricity markets perspective. The measures addressed until now, transmission and storage, are complemented by an analysis of an alternative: curtailment of renewable generation. The acceptance of this measure will play an increasing role for a cost-efficient integration of renewables. An intuitive example is that it is not efficient to dimension offshore connections at the nameplate capacity of the wind park, but that accepting curtailment should be part of the optimisation.

Combining results from the different papers leads to the conclusion that an integrated operation of meshed offshore grids and generation seems best. Strategic behaviour between actors is thus avoided, while stable investment conditions can be supported. A feed-in tariff or a combination of tendering and feed-in tariffs could be a suitable support mechanism, allowing a co-operation of generation and transmission. The regulatory and policy framework should be adapted to meet the characteristics of offshore grids. Doing so can foster the cost-efficient deployment of both transmission and generation.

Resumé

Denne PhD-afhandling beskæftiger sig med integration af vindenergi i offshore grids fra et økonomisk perspektiv. Afhandlingen består af en generisk del samt otte selvstændige publikationer. Som en af første publikationer behandler den markeds- og driftsspørgsmål og de deraf følgende investeringseffekter under forskellige reguleringsregimer.

Offshore grids mellem flere lande kombinerer integration af vindenergi og international el-handel. Derudover påvirker inkluderingen i et offshore grid økonomien af en havvindmøllepark. Det vises, at forbindes en havvindmøllepark til et handelskabel og dermed afregnes efter nodal pricing princippet frem for på et nationalt marked, er der risiko for at indtjeningen til møllen reduceres. Ydermere kan belastning af nettet forhindre vindmølleparken i at rette op på eventuelle forudsigelsesfejl gennem en balanceringsgruppe på land. Med udgangspunkt i en netvirksomhed og en vindmøllepark analyseres incitamenterne for strategisk adfærd, hvor det viste sig at afhængig af den gældende regulering, vil de være tilbøjelige til at melde enten højere eller lavere produktion end forventet ud. Dette kan føre til sub-optimal udnyttelse af infrastrukturen med socio-økonomisk tab som følge. Hvis den gældende regulering indrettes således, at der tages højde for disse specielle egenskaber ved offshore grids, kan de socio-økonomiske tab og de mulige uønskede fordelingseffekter undgås. Ud fra et operationel real options approach kan det ydermere vises hvorledes forskellige støttemekanismer samt eventuelle forbindelser til flere lande kan påvirke investeringsbeslutningen for en havvindmøllepark og indkomsten for netvirksomheden. Disse investeringsbeslutninger er ligeledes analyseret i et policy studie vedrørende mulige kombinationer af støttemekanismer og internationale samarbejdsmuligheder, hvor landene kan samarbejde om at nå deres individuelle mål for vedvarende energi. På mellemlangt sigt er tendering i forbindelse med joint projects en mulig løsning.

Case studier vedrørerende Kriegers Flak offshore hub i Østersøen samt spørgsmålet omkring lagring af energi til havs understøtter disse analyser. Det fremgår, at inklusion af vindproduktion omtrent halverer flaskehalsindtægterne. Ydermere fås det, at mens det at bygge og køre et adiabatisk trykluftlager vil være teknisk muligt, vil det ud fra et elmarkedsperspektiv være en mindre attraktiv løsning end en løsning på land. De hidtil gennemgåede midler, transmission og lagring, suppleres af en analyse af et alternativ: curtailment af vedvarende energiproduktion. Hvis anvendelsen af dette instrument accepteres, vil det spille en stadig større rolle for omkostningseffektiv interegration af vedvarende energi. Et intuitivt eksempel er, at det ikke vil være efficient at dimensionere tilslutningen med en kapacitet svarende til produktionskapaciteten af havvindmølleparken, men snarere at acceptere at curtailment er en betingelse for at opnå den optimale kombination. Kombineres resultaterne fra de forskellige artikler fås konklusionen, at offshore transmission og energiproduktion skal køres som integrerede systemer. På den måde undgås strategisk adfærd fra aktørernes side, mens stabile investeringsbetingelser opretholdes. En feed-in tariff – eventuelt i kombination med tendering – er et passende styringsmiddel, der samtidig understøtter samkøring af produktion og transmission. Den gældende regulering skal indrettes således, at der tages højde for egenskaberne ved offshore grids. I så fald kan man opnå omkostningseffektiv transmission såvel som produktion.[1]

[1]Thanks to Lise-Lotte Pade for assisting with the translation into Danish.

Zusammenfassung

Diese kumulative Dissertation beleuchtet die Integration von Windenergie in Offshore-Netze unter ökonomischen Gesichtspunkten. Sie besteht aus einer zusammenfassenden Einleitung sowie acht Veröffentlichungen. Das Zusammenspiel von Strommärkten und Offshore-Netzen und daraus folgende Anreize unter verschiedenen Rahmenbedingungen sind ein bisher wenig beachtetes Forschungsgebiet. Sie werden hier behandelt.

Offshore-Netze zwischen mehreren Ländern kombinieren die Übertragung von Stromerzeugung aus Windenergie mit internationalem Stromhandel. Die Einbeziehung in ein derartiges Offshore-Netz kann jedoch die Wirtschaftlichkeit eines Offshore-Windparks beeinflussen. Es zeigt sich, dass das Spotmarkt-Einkommen eines Offshore-Windparks unter *nodal pricing* geringer ist, wenn dieser in ein Seekabel zwischen zwei Ländern eingebunden ist. Darüber hinaus können Engpässe im Kabel verhindern, dass der Windpark auftretende Vorhersagefehler mit Hilfe eines Onshore-Bilanzkreises ausgleicht. Ein analytischer Ansatz mit einem Übertragungsnetzbetreiber sowie einem Offshore-Windpark zeigt mögliche Anreize zu strategischem Verhalten auf. Je nach Ausgestaltung des regulatorischen Umfeldes könnten sie veranlasst sein, mehr oder weniger Windproduktion als erwartet am Day-Ahead-Spotmarkt zu verkaufen. Dies kann zu einer suboptimalen Auslastung der Netzinfrastruktur führen. Solche Effekte lassen sich vermeiden, indem die besonderen Gegebenheiten von Offshore-Netzen berücksichtigt werden. Ferner wird mittels eines Realoptionen-Ansatzes dargelegt, wie verschiedene Fördermechanismen und Verbindungen zu zusätzlichen Ländern das Einkommen eines Offshore-Windparks und die Engpasserlöse der Übertragungsnetzbetreiber beeinflussen. Die Investitionsperspektive wird weiterhin mit einer Studie über die Kombinationsmöglichkeiten von Fördermechanismen und internationalen Kooperationsmaßnahmen beleuchtet. In der näheren Zukunft erscheint eine Ausschreibungslösung für gemeinsame Projekte am praktikabelsten.

Weitere Analysen über den geplanten Offshore-Knoten bei Kriegers Flak in der Ostsee und zur Frage möglicher Offshore-Energiespeicherung ergänzen die vorherigen Betrachtungen. Die Fallstudie zu Kriegers Flak belegt, dass die Windenergieerzeugung die Engpasserlöse ungefähr halbiert. Der Betrieb eines adiabaten Offshore-Druckluftspeichers erscheint technisch machbar. Aus mehreren Gründen ist dies aus einer energiewirtschaftlichen Perspektive nachteilig gegenüber einem Onshore-Standort. Eine Alternative zu den bisher angeführten Maßnahmen, Stromübertragung oder Speicherung, kann reduzierte Erzeugung (Einspeisemanagement) sein. Die Akzeptanz dieser Maßnahme kann eine wichtige Rolle bei der effizienten Einbettung von Erneuerbaren Energien einnehmen. Ein eingängiges Beispiel ist, dass es ineffizient ist, einen Offshore-Netzanschluss entsprechend der Gesamtleistung eines Offshore-Windparks zu dimensionieren.

Insgesamt erscheint eine gemeinsame Betriebsweise von internationalen Offshore-Netzen und -Windenergie optimal. So lässt sich strategisches Verhalten vermeiden, während verlässliche Investitionsbedingungen geschaffen werden. Ein Einspeisetarif oder eine Kombination mit einer Ausschreibungslösung könnten hierzu den passenden Fördermechanismus darstellen. Die regulatorischen Bedingungen sollten so gestaltet werden, dass sie die Eigenschaften von Offshore-Netzen berücksichtigen. Dies kann zu einem effizienten Ausbau des Offshore-Netzes und der Offshore-Windparks beitragen.

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List of Abbreviations

AC .... Alternating Current
ACER .... Agency for the Cooperation of Energy Regulators
bn .... Billion
CAES .... Compressed Air Energy Storage
CAPEX .... Capital Expenditure
CCS .... Carbon Capture and Storage
CSC .... Current Source Converter
DC .... Direct Current
EEZ .... Exclusive Economic Zone
ENTSO-E .... European Network of Transmission System Operators for Electricity
EWEA .... European Wind Energy Association
GW .... Gigawatt
GWh .... Gigawatt-hour
HVDC .... High Voltage Direct Current
IEA .... International Energy Agency
LCOE .... Levelised Cost of Energy
MW .... Megawatt
MWh .... Megawatt-hour
NREAP .... National Renewable Energy Action Plans
NSCOGI .... North Sea Countries' Offshore Grid Initiative
OFTO .... Offshore Transmission Operator
PV .... Photovoltaics
RES .... Renewable Energy Sources
RES-E .... Electricity from Renewable Energy Sources
TYNDP .... Ten-Year Network Development Plan
UCTE .... Union for the Coordination of Transmission of Electricity
UNCLOS .... UN Law of the Sea Convention
VSC .... Voltage Source Converter

List of Publications

This chapter provides an overview of all publication activities during the course of the PhD studies. It starts with a listing of all papers that are part of the PhD thesis and continues with other journal articles, conference papers, reports and talks which do not constitute an integral part of the thesis.

Research papers included in PhD thesis

1. Interconnector capacity allocation in offshore grids with variable wind generation. Schröder, Sascha Thorsten. *Wind Energy*, 2012, doi: http://dx.doi.org/10.1002/we.537.
2. Electricity market design in offshore grids – strategic incentives under different regulatory regimes. Schröder, Sascha Thorsten.
3. The impact of an offshore electricity hub at Kriegers Flak on power markets. Schröder, Sascha Thorsten; Larsen, Helge V.; Meibom, Peter. *Proceedings of the European Wind Energy Conference 2010*, Warsaw.
4. Compressed air energy storage in offshore grids. Schröder, Sascha Thorsten; Crotogino, Fritz; Donadei, Sabine; Meibom, Peter. *Risø International Energy Conference 2011.* Part of: Energy systems and technologies for the coming century (ISBN: 978-87-550-3903-2), 409-418, Danmarks Tekniske Universitet, Risø Nationallaboratoriet for Bæredygtig Energi, Roskilde.
5. Joint support and efficient offshore investment: market and transmission connection barriers and solutions. Schröder, Sascha Thorsten; Kitzing, Lena; Klinge Jacobsen, Henrik; Pade Hansen, Lise-Lotte. *Renewable Energy Law and Policy Review*, 2/2012, 112-120.
6. Regulating future offshore grids: economic impact analysis on wind parks and transmission system operators. Kitzing, Lena; Schröder, Sascha Thorsten. *Proceedings of the European IAEE 2012 Conference*, Venice. Best Student Paper Award.
7. Curtailment of renewable generation: economic optimality and incentives. Klinge Jacobsen, Henrik ; Schröder, Sascha Thorsten. *Energy Policy*, 2012, 49, 663-675.
8. Power market design choices: optimal timing for wind energy. Schröder, Sascha Thorsten. *Submitted to Applied Energy, March 2012.*

Other journal articles

1. Fuel Cell-based micro-combined heat and power under different policy frameworks – an economic analysis. Pade, Lise-Lotte; Schröder, Sascha Thorsten. *Energy Conversion and Management*, forthcoming.
2. Network Regulation and Support Schemes - How Policy Interactions Affect the Integration of Distributed Generation. Ropenus, Stephanie; Klinge Jacobsen, Henrik; Schröder, Sascha Thorsten. *Renewable Energy*, 2011, 36, 1949-1956.
3. Support schemes and ownership structures - the policy context for fuel cell based micro-combined heat and power. Schröder, Sascha Thorsten; Costa, Ana; Obé, Elisabeth. *Journal of Power Sources*, 2011, 196, 9051-9057.
4. Parallel feed-in grids for renewable energy: Contesting the natural monopoly through the back door? Schröder, Sascha Thorsten. *International Journal of Distributed Energy Resources*, 2010, 6, 311-324.

Other journal article submissions

1. Cooperation mechanisms to achieve EU renewable targets. Klinge Jacobsen, Henrik; Pade, Lise-Lotte; Schröder, Sascha Thorsten; Kitzing, Lena. *Renewable Energy, September 2012.*
2. Policy schemes, operational strategies and system integration of residential co-generation fuel cells. Pade, Lise-Lotte; Schröder, Sascha Thorsten; Münster, Marie; Birkl, Christoph; Morthorst, Poul Erik; Obé, Elisabeth; Kötter, Editha; Huber, Andreas; Costa, Ana; Kroff, Pablo; Ropenus, Stephanie. *International Journal of Hydrogen Energy, June 2012 – revisions submitted, October 2012.*

Other conference paper presentations

1. The effects of meshed offshore grids on offshore wind investment – a real options analysis. Schröder, Sascha Thorsten; Kitzing, Lena. Poster presentation. *Proceedings of the EWEA 2012 Conference*, Copenhagen.
2. Electricity market design options and balancing rules in offshore grids. Schröder, Sascha Thorsten ; Sundahl, Lasse. *10th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants*, Aarhus.
3. Joint support schemes and efficient offshore investment: Market and transmission connection barriers and solutions. Schröder, Sascha Thorsten; Kitzing, Lena; Klinge Jacobsen, Henrik; Pade Hansen, Lise-Lotte. *Proceedings of the EWEA 2011 Offshore Conference*, Amsterdam.

4. Joint support schemes for renewable generation and barriers for implementation. Klinge Jacobsen, Henrik; Hansen, Lise-Lotte Pade; Schröder, Sascha Thorsten; Kitzing, Lena. *12th Global Conference on Environmental Taxation*, Madrid, 2011.
5. Optimal power market timing for wind energy. Schröder, Sascha Thorsten; Weber, Alexander. *Proceedings of the EWEA 2011 Conference*, Brussels.
6. Efficiency of continuous double auctions in the electricity market. Weber, Alexander; Schröder, Sascha Thorsten. *8th International Conference on the European Energy Market*, Zagreb. Part of: Energy Market 2011 (ISBN: 978-1-61284-285-1), 87-92.
7. Support schemes and ownership structures – The policy context for fuel cell-based micro-combined heat and power. Schröder, Sascha Thorsten. *Fuel Science and Technology Conference 2010*, Zaragoza. Keynote speech.
8. Market impact of an offshore grid – a case study. Schröder, Sascha Thorsten; Meibom, Peter; Spiecker, Stephan; Weber, Christoph. *IEEE Power and Energy Society 2010 General Meeting, Minneapolis.* Part of: Conference proceedings (ISBN: 978-1-42448-357-0), 2010, IEEE Power and Energy Society.
9. The Impact of an Offshore Electricity Hub at Kriegers Flak on Power Markets. Schröder, Sascha Thorsten; Larsen, Helge V.; Meibom, Peter. *Proceedings of the European Wind Energy Conference 2010*, Warsaw.
10. Allocation of Interconnector Capacity with In-Between Stochastic Generation. Schröder, Sascha Thorsten. *8th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Farms*, Bremen, 2009.
11. Network Regulation and Support Schemes. Ropenus, Stephanie; Schröder, Sascha Thorsten; Klinge Jacobsen, Henrik. *8th Conference on Applied Infrastructure Research (INFRADAY)*, Berlin, 2009.

Reports

1. Proposal of new variants for day ahead, intra-day and balancing markets/mechanisms in Europe. Weber, Alexander; Schröder, Sascha Thorsten. OPTIMATE project report, 2011.
2. Analyses of models for promotion schemes and ownership arrangements. Pade, Lise-Lotte; Schröder, Sascha Thorsten; Münster, Marie; Morthorst, Poul Erik. FC4home project report, 2011.
3. Regulatory strategies for selected Member States (Denmark, Germany, Netherlands, Spain, the UK). Nieuwenhout, Frans; Jansen, Jaap; van der Welle, Adriaan; Olmos, Luis; Cossent, Rafael; Gómez, Tomás; Poot, Jos; Bongaerts, Martijn; Trebolle, David; Doersam, Barbara; Bofinger, Stefan; Lichtner, Patrick; Gerhardt, Norman; Klinge Jacobsen, Henrik; Ropenus, Stephanie; Schröder, Sascha Thorsten; Auer, Hans; Weissensteiner, Lukas; Prüggler, Wolfgang; Obersteiner, Carlo; Zach, Karl. IMPROGRES project report, 2010.
4. Support Schemes and Ownership Structures. Ropenus, Stephanie; Schröder, Sascha Thorsten; Costa, Ana; Obé, Elisabeth. FC4home project report, 2010.
5. Market and regulatory incentives for cost efficient integration of DG in the electricity system. Nieuwenhout, Frans; Jansen, Jaap; van der Welle, Adriaan; Olmos, Luis; Cossent, Rafael; Gómez, Tomás; Poot, Jos; Bongaerts, Martijn; Trebolle, David; Doersam, Barbara; Bofinger, Stefan; Gerhardt, Norman; Klinge Jacobsen, Henrik; Ropenus, Stephanie; Schröder, Sascha Thorsten; Auer, Hans; Weissensteiner, Lukas; Prüggler, Wolfgang; Obersteiner, Carlo; Zach, Karl. IMPROGRES project report, 2010.

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1. On success factors of Danish wind energy expansion. Schröder, Sascha Thorsten. Short interview in the *ARD Morgenmagazin/NDR Aktuell* (German public broadcasting), 22.10.2012.
2. OPTIMATE – an Open simulation Platform to Test Integration in MArkeT design of massive intermittent Energy. Biegala, Nicolas; Bourmaud, Jean-Yves; Schröder, Sascha Thorsten. *Smart Grids 2012 Conference&Exhibition*, Paris.
3. The OPTIMATE model - agent-based integration of wind power in energy systems models. Schröder, Sascha Thorsten. *EWEA 2012 Conference*, Copenhagen.
4. Wind energy and society. Schröder, Sascha Thorsten. *DTU Wind Power Day 2012*, Roskilde.
5. Wind power and the power market. Schröder, Sascha Thorsten. *EWEA2012 Pre-Conference Grid Seminar, Danish Wind Industry Association*, Copenhagen.
6. Energy Supply Technologies: Wind Power. Schröder, Sascha Thorsten; Jørgensen, Birte Holst. *IEA Committee on Energy Research and Technology – Experts' Group on R&D Priority Setting and Evaluation. Monitoring Progress towards a Clean Energy Economy*, Paris, 2011.
7. Minimizing the cost of integrating DG and incentives for localisation of DG investments in networks. Cossent, Rafael; Olmos, Luis; Gómez, Tomás; Mateo, Carlos; Klinge Jacobsen, Henrik; Schröder, Sascha Thorsten; Ropenus, Stephanie. *CEPS/ECN Workshop: The future of EU electricity grids: Who will benefit from smart grids and at what costs?*, Brussels, 2010.

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1 Approach

1.1 Research interest

What this study is about The role of electricity generation based on renewable energy sources increases quickly in Europe. This development is a challenge both from a technical and an economic point of view. In a broad sense, this thesis deals with the integration of renewable energy in European electricity markets, the leading question being: how does renewable electricity generation react to market signals under different policy frameworks and how could these be amended to achieve desirable outcomes? Evidently, only topical areas within such a broad question can be covered. In a narrower sense, the focus of the analysis is on wind energy, especially on how it can be integrated in international offshore grids. There are several starting points for this question: first, a number of European contries plan to install considerable offshore wind energy capacities within the next decades. Second, due to meteorological characteristics, wind energy exhibits spatial levelling effects over large geographical areas. Instead of using local storage with associated efficiency losses, transmission over large distances with lower losses is an alternative. This is one of the driving factors behind the plans to increase cross-border transmission capacities. Linking these two issues gives international subsea transmission lines with integrated offshore wind generation. Third, there are already several studies and methodological approaches about the optimal layout of such offshore grids, usually taking installed wind energy capacities at different locations as input. This is why this thesis focuses more on market-operational and policy aspects. An example for this is the case that an interconnector between an offshore wind park and its home country is blocked due to international power trading. Hence, it cannot contribute excess generation to the onshore balancing activities of its owner. Such effects have several implications for regulatory design choices. Moreover, they may affect investment incentives in offshore wind generation and transmission infrastructure.

What this study is not about There are a number of related research areas that this thesis does *not* focus on, although short introductions to these related topics may be given in the introductory part (chapters 2-5). The main related areas that are beyond the scope of this work are:

- A comparative technology analysis of a cost-efficient path towards a European electricity system strongly based on renewable energy sources. More precisely, the national offshore capacity installation goals are regarded as exogenously given, as is the tendency towards more interconnection between countries.
- maritime and spatial planning in general, and offshore wind siting more specifically.
- Technical questions of offshore grids. Especially the field of meshed/multi-terminal HVDC grids poses a number of challenges to electrical engineers – which will have to be solved before large-scale meshed offshore grids can be built.
- Offshore grid topology, i.e. the layout of offshore grids, including their development steps over time.

1.2 Outline

The generic introductory part of this thesis is composed of a few words on background developments, followed by more specific chapters on offshore grids, support schemes and electricity markets. Their goal is to provide the necessary literature background to the papers presented in the appendices, as well as place the papers with regard to the literature and highlight connections between them. However, the main contributions of this thesis lie within the papers.

Figure 1 places the research papers which form part of this thesis within the major research fields of wind integration, electricity markets and support schemes. Wind integration is sub-categorised into on- and offshore topics and electricity market questions are split into investment and operation questions. The numbers in the figure refer to the single research papers which are contained as appendices in this thesis:

I. Interconnector capacity allocation in offshore grids with variable wind generation. Schröder, Sascha Thorsten. *Wind Energy*, 2012, doi: http://dx.doi.org/10.1002/we.537.

II. Electricity market design in offshore grids – strategic incentives under different regulatory regimes. Schröder, Sascha Thorsten.

III. The impact of an offshore electricity hub at Kriegers Flak on power markets. Schröder, Sascha Thorsten; Larsen, Helge V.; Meibom, Peter. *Proceedings of the European Wind Energy Conference 2010*, Warsaw.

IV. Compressed air energy storage in offshore grids. Schröder, Sascha Thorsten; Crotogino, Fritz; Donadei, Sabine; Meibom, Peter. *Risø International Energy Conference 2011.* Part of: Energy systems and technologies for the coming century (ISBN: 978-87-550-3903-2), 409-418, Danmarks Tekniske Universitet, Risø Nationallaboratoriet for Bæredygtig Energi, Roskilde.

V. Joint support and efficient offshore investment: market and transmission connection barriers and solutions. Schröder, Sascha Thorsten; Kitzing, Lena; Klinge Jacobsen, Henrik; Pade Hansen, Lise-Lotte. *Renewable Energy Law and Policy Review*, 2/2012, 112-120.

VI. Regulating future offshore grids: economic impact analysis on wind parks and transmission system operators. Kitzing, Lena; Schröder, Sascha Thorsten. *Proceedings of the European IAEE 2012 Conference*, Venice. Best Student Paper Award.

VII. Curtailment of renewable generation: economic optimality and incentives. Klinge Jacobsen, Henrik ; Schröder, Sascha Thorsten. *Energy Policy*, 2012, 49, 663-675.

VIII. Power market design choices: optimal timing for wind energy. Schröder, Sascha Thorsten. *Submitted to Applied Energy, March 2012.*

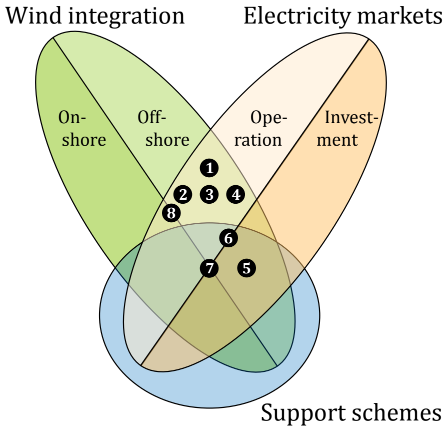

Figure 1: Modified Venn diagram on the location of the papers in different research fields

As illustrated, the majority of papers lies within the combination of offshore wind energy and operational electricity market questions or borders them. Papers I-IV focus on market-operational aspects of offshore grids. A current widespread assumption is that a meshed offshore grid is an infrastructure that can yield socio-economic benefits. At a stakeholder level, publications deal mainly with regulatory questions about investment incentives (see e.g. Levêque et al., 2012), which is certainly an important subject to be dealt with early. However, possible operational and investment effects on involved offshore wind parks have not been addressed sufficiently yet. Arguing from an electricity markets perspective, this dissertation shows that stakeholder roles and responsibilities may affect the expectable benefits from offshore grids (papers I and II). Regulatory choices for electricity markets both at the hourly and sub-hourly time level play a role. Paper III is a case study of the planned first offshore hub Kriegers Flak in the Baltic Sea, while paper IV addresses the question how storage placed in an offshore grid is different from storage capacity placed onshore. The argumentation of papers VI-VIII extends also to onshore wind integration or investment questions, respectively. Paper no. V focuses on policy questions, i.e. how support to offshore wind investment could be granted jointly by several countries. The following part deals with the research methodology of the different papers in greater detail.

1.3 Research methods

This section explains the research methods of the different papers successively, mostly connecting them in groups of two.

Papers I and II are the first ones to deal with wind stochasticity in meshed offshore grids. This issue is addressed from a power market perspective: due to the topic, both papers share several characteristic traits. They account for both spot and balancing market issues, thus considering different time steps that can play a role for the involved stakeholders, and regard several suggestions about pricing rules in an offshore grid. The novelty of the setup lies in the fact that the offshore hub constitutes an electricity infrastructure island with generation, but no demand, that can be blocked from access to its home country due to international power flows. Thus, from an operations research perspective (see below), it constitutes a seperate network node that may be subject to nodal pricing when determining optimal power flows. With a simple analytical-exemplary setup, Paper I illustrates that if an offshore wind farm feeds into a transmission cable between two countries and is subject to nodal pricing, the lower price applies. The alternative is reduced income from congestion rents. In other words, the offshore wind farm tends to be locked out from the high-price market. This has also implications for balancing matters, as the illustrative case study points out. The trade-off between congestion rents and wind farm income can be defined by regulatory choices, as the reallocation analysis between stakeholders shows. Paper II partly draws on these concepts, also regarding an offshore wind farm between several countries. It assumes two profit-maximising stakeholders, an offshore wind farm and a transmission system operator. Depending on the regulatory setup, one of these actors nominates offshore wind generation for the day-ahead market. The analytical model shows strategic incentives to use this right in a private profit-maximising way. Finally, an illustrative case study confirms the benefits of strategic bidding in comparison to respective truth-telling.

Papers III and IV are case studies based on a mixed-integer cost minimisation model belonging to the academic field of operations research (see CONNOLLY et al., 2010), for a wide overview of energy systems models). The WILMAR Joint Market Model has an hourly time resolution of a calendar year and the geographical resolution in Europe is mostly identical with national borders. It is detailed with regard to a number of power sector characteristics, e.g. primary and secondary reserves per country, and allows for different ways of computing power flows between countries. Its special feature in comparison to other models is that it can take stochasticity into account. More precisely, this encompasses wind fluctuations and thermal power plant outages. This stochasticity is implemented by successive optimisation steps for a given hour T: after the scheduling of the day-ahead market, an optimal system scheduling is recomputed all 3 hours until the hour T is reached, taking changed wind forecasts and stochastic unit outages into account. Paper III analyses the planned offshore hub at Kriegers Flak with this model. The focus of the analysis is on socio-economic benefits and congestion rents. Paper IV is a pre-feasibility study for the technology of adiabatic Compressed Air Energy Storage which may become both a substitute and complement to additional international transmission lines. It covers the technology, geological possibilities in Northern Germany and the North Sea and compares an onshore location with an offshore location. The latter case could be an offshore hub in the long term, being connected to different shores by HVDC cables. The focus of the analyses is on the differences in operational patterns of the units placed on- or offshore, providing interesting additional reasons for the intuitive finding that it is better to place storage units onshore.

Paper V is a qualitative policy analysis that investigates the possibilities for several countries giving joint support to offshore wind energy. Due to its marine nature and possibly meshed grid infrastructures, the technology may be an optimal starting point for such an effort. The paper starts with a review of EU legislation on the subject, proceeds with addressing implementation barriers, and judges the combinations between cooperation mechanisms and main support schemes. The policy analysis finishes with suggestions on possibly feasible combinations for offshore wind in the short and long term.

Paper VI links operational and investment perspectives, hence encompassing all of the aforementioned papers to different degrees. The methodological approach are real options from operational benefits that are numerically estimated using Monte Carlo simulations. Starting from different possible pricing regimes in an offshore node (inspired by Papers I and II), the private returns of an offshore wind park are computed, as are congestion rents in interconnectors. These income parameters are based on a number of artificial price processes in a varying number of countries connected to the offshore hub. Moreover, line failures are simulated. The results indicate hence both the expected average income and the income risk associated with it. The relative differences of the income constellations under different regulatory regimes allow for policy recommendations e.g. with regard to support scheme design.

Papers VII and VIII address more general topics in a wider perspective on issues related to offshore grids. In future energy sytems with high shares of renewable generation, curtailment will play an increasing role – both with respect to system and network constraints, but also during periods of excess generation with possibly negative power market prices. Paper VII is widely a qualitative review on the different reasons for curtailing renewable electricity generation, complemented by quantative examples. Curtailment of wind energy is categorised into involuntary and voluntary curtailment from the operator perspective. The first is based on external requirements such as network constraints, whereas the second is based on power market signals. To the authors' knowledge, it is the first review article addressing various kinds of curtailment from an economic point of view.

Paper VIII is a brief quantitative study on timing aspects in electricity markets. It presents several qualitative timing dimensions of power markets and translates these into simple, yet interesting quantitative simulations. Thus, it is calculated how different timing of the main market affects the cost of wind power integration. The contribution lies in the classification of power market timing options and an approximate estimation of their effect on wind power integration costs.

1.4 Structure of the generic part of the thesis

The thesis is composed of a generic part, providing the necessary background to the different disciplines and linking the different subjects, and the appendix papers. By the virtue of being a cumulative thesis, most of the academic contributions lie in the papers and focus on different, yet related topics – as described above. The introductory part, starting immediately after this paragraph, is structured as follows:

A short background chapter briefly addresses the driving factors for renewable energy resources and general aspects of offshore wind power. The following chapter on offshore grids gives an overview of the developments in the field, touching on technical as well as legal aspects and giving an overview of the different suggestions worldwide. As these are partly based on industry initiatives, the chapter draws on conceptual suggestions and technical reports as well as the most relevant academic literature. The successive chapters on support schemes and electricity markets give brief introductions into these academic fields. The studies presented in the papers are related with regard to the literature and with regard to each other at the end of each chapter. However, the goal of the literature context in the generic part is not completeness, but brevity: as all papers relate themselves to their main sources and academic context, a repetition of these accounts is avoided. The generic part of the thesis finishes with the main cross-topical conclusions.

2 Background

2.1 Driving factors for renewable energy resources

The contents of this study relate mainly to a European context. For this reason, the structure of this section is aligned to political goals of the European Union. Its energy policy focuses on three pillars: sustainability, competitiveness and energy security (European Commission, 2006). These objectives could also foster the erection of offshore grids in other parts of the world in a long-term perspective. Single pillars may experience a different weighting in a non-EU context, though.

Sustainability refers mainly to global warming due to increasing CO_2 emissions. There is a general scientific consensus that climate change is anthropogenic (Oreskes, 2004, IPCC, 2007) and can lead to global changes with severe effects, e.g. with regard to a rising sea level, changed temperature and precipitation patterns and following migration streams between continents. Besides the advent of adaptation measures, the main political focus is – still – on mitigation, which is also assumed to be the far cheaper option (Stern, 2007). More specifically, mitigation implies that the currently carbon-intensive energy consumption will have to be changed: a reduction in consumption, CO_2-free technologies such as Renewable Energy Sources (RES) and Carbon Capture and Storage (CCS) are the measures considered. Moreover, this could support other sustainability criteria, e.g. local air quality (European Commission, 2006). *Competititiveness* aims at establishing an internal European energy market, ensuring the access to reasonably priced energy throughout the whole EU while helping maintaining employment levels (European Commission, 2006). *Energy security* targets a diversified combination of energy sources, minimising the import dependency for different fuels from specific countries. Specifically for the electricity sector, Directive 2005/89/EC (European Parliament and Council, 2006b) sets the framework for security of supply and sufficient infrastructure investment.

The EU has established the so-called 20/20/20 goals, i.e. CO_2 emissions should be reduced by 20% by 2020 (in comparison to 1990), energy efficiency shall be increased by 20% in comparison to benchmark levels and the RES share across all sectors shall be increased to 20%. Based on this overall target, all Member States are subject to individual targets and need to show their intended continuous development through National Renewable Energy Action Plans (NREAPs). In all Member States' plans, wind energy plays a role thanks to its cost competitiveness in comparison with other electricity-generating Renewable Energy Sources (RES-E) technologies. Offshore wind energy is still notably more expensive (Edenhofer et al., 2012), but the vast resources, expected cost decreases, limited public acceptance issues and economic growth in coastal regions render it into an option being considered by most Western European coastal countries.

2.2 History and prospects of offshore wind energy

The first experimental installations to generate electricity with wind power were erected around 1890, but the major development efforts leading to the current status of the industry were only made after the oil crises in the 1970/80s. All large-scale turbines existing

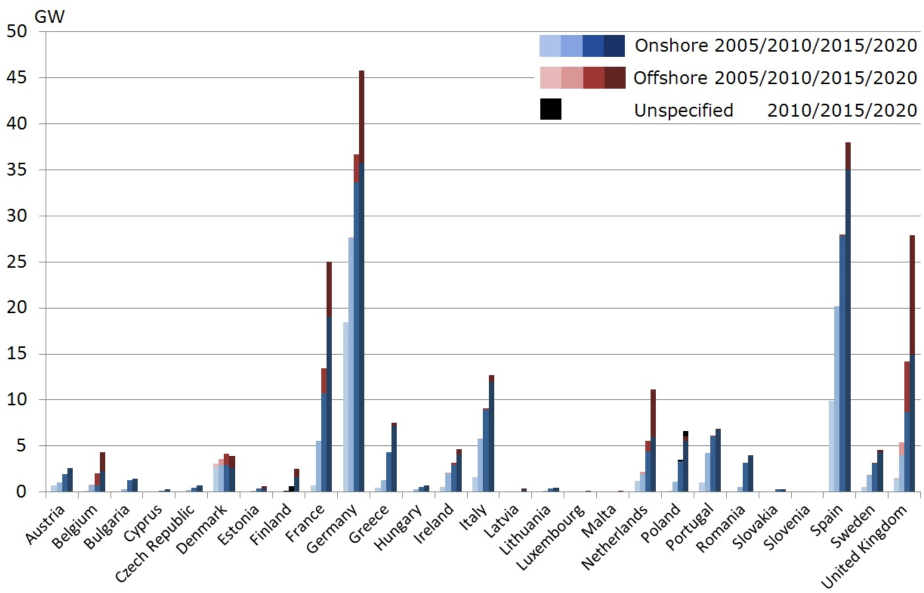

Figure 2: Historical development and National Renewable Energy Action Plans targets for on- and offshore wind energy, based on Beurskens et al. (2011)

nowadays follow the so-called 'Danish design', i.e. a horizontal-axis turbine with three blades constituting an upwind rotor. Based on these developments for onshore applications, this proven concept is applied offshore as well, although the different conditions led to the development of turbines designated specifically for the offshore market. Suggestions for different designs that may have competitive advantages at offshore locations, e.g. with two blades only or vertical rotors (see e.g. Vita, 2011), are only prevalent as sketches or academic evaluations.

Offshore locations offer a higher number of full-load hours than possible onshore, though accessibility, grid connection and other aspects are generally more complicated and costly. Nevertheless, the vast resources (see e.g. Wiser et al., 2012, and sources therein) render it attractive options especially in densely populated coastal countries. The first offshore wind farm was erected in 1991 and is composed of 11 turbines west of the Danish island of Lolland. This did not lead to a substantial deployment of offshore resources in the following years because of the higher costs associated. Figure 2 shows historical levels of installed wind capacity for 2005 and 2010 in the EU as well as the expected installed capacities for 2015 and 2020 according to the single Member States' National Renewable Energy Action Plans (NREAPs). In 2005, under 1.7% of total wind capacity in the EU was installed offshore, notably in Denmark and the United Kingdom. With additional installations in these and other countries, e.g. the Netherlands, the installed capacity was more than tripled by 2010. For 2015 and 2020, a number of coastal countries expect offshore wind energy to play an important role in their RES portfolio, especially Belgium, Denmark, the Netherlands, France, Germany and the United Kingdom. Other coastal countries as

Portugal or Sweden decided to focus strongly on extending their onshore installations. The abovementioned countries with extensive offshore plans cover all of the EU Member States bordering the North Sea, providing good reasons for industry collaboration. With Sweden's yet large unused onshore resources, the picture is different for the Baltic Sea. According to the NREAPs, the 44.2 GW of offshore wind energy will account for about 21% of installed capacity by 2020. There are no official declarations on RES installations beyond 2020, which is why alternative sources need to be considered. The NREAP numbers are roughly in line with the 'high' wind installation scenario by Zervos and Kjær (2008), suggesting 150 GW of offshore and 200 GW of onshore installations by 2030.

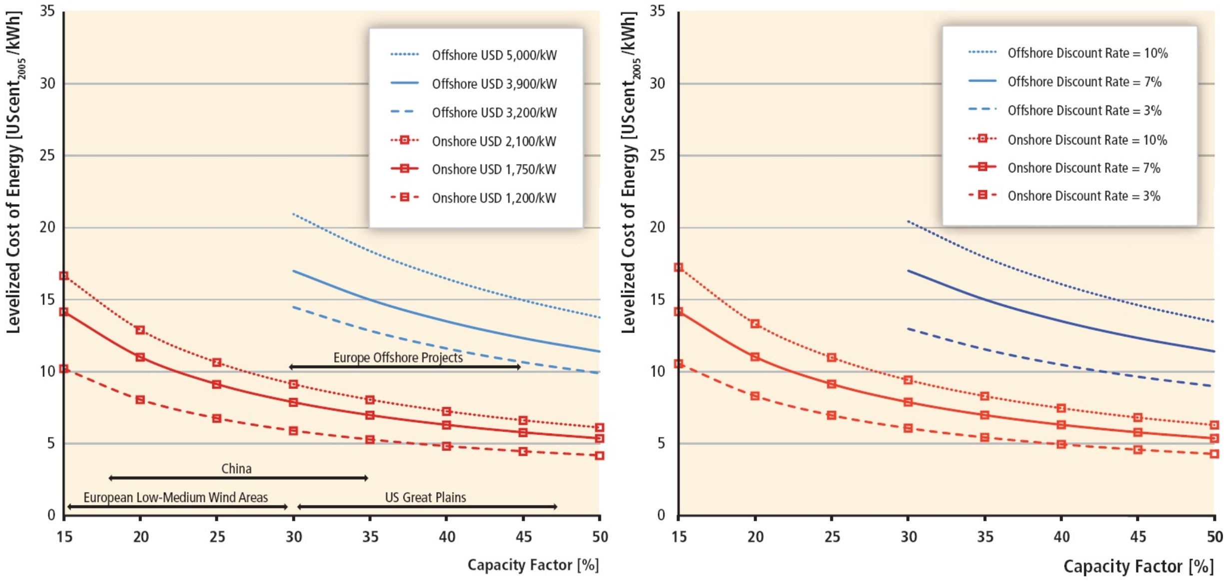

Figure 3: Estimated levelised cost of on- and offshore wind energy for different investment costs and capacity factors (Wiser et al., 2012)

The current levelised cost of energy (LCOE) of offshore wind power is contrasted with onshore wind power in figure 3, showing sensitivities for investment cost and discount rates. Investment costs of the IEA Blue Map scenario for 2010 are in the range of USD_{2008} 3-3.7/MW and the Danish Technology Catalogue assumes costs at the upper end of this range (see comparison in Schröder and Jørgensen, 2011, or Green and Vasilakos, 2012, for an alternative overview). These are even higher than the maximum values indicated in earlier sources such as Morthorst et al. (2009), which is an indicator that the learning curves are less steep than expected. Due to the immaturity of the offshore wind industry, all aforementioned sources agree that considerable cost reductions can be expected - Wiser et al. (2012) naming a range between 10 to 40%, the others about 15-20% by 2020. In every case, offshore wind will stay more expensive than deploying onshore resources, but costs of single projects vary greatly between single sites, depending mainly on water depth and distance to shore.

3 Offshore grids

Offshore grids are still a comparatively young topic and therefore, it is useful to introduce defitinions which will be applied during the remainder of this thesis:

Offshore grids connect (a) electricity generation situated offshore with onshore demand centres or (b) different electricity systems via large-distance subsea interconnections.

Meshed offshore grids connect at least one offshore generation site with at least two countries.

The first of the above definitions is the broader one and encompasses radial connections of offshore wind generation to national onshore networks as well as numerous subsea interconnections between countries. The definition is formulated in a way that it covers the notion of all main concepts (see section 3.1) currently under discussion. Furthermore, it focuses on the connection of offshore generation, typically wind or ocean energy. By doing so, it excludes alternative motivations for offshore grids that may also play a role, e.g. the connection of Norwegian oil platforms to the mainland. The possible combination with offshore wind generation, as discussed by Øyslebø and Korpås (2011), approximates it to the above definition, but offshore demand from the oil rigs is not covered in a narrow sense. The same applies to Hang et al. (2011), suggesting to connect oil platforms to international power transmission lines. Nevertheless, the author proposes that these niche applications do not reflect the main part of the offshore grid discussions and concepts and should therefore be excluded from the definition to keep it as precise as possible. Contrarily, the second definition about meshed offshore grids is rather wide: its smallest possible configuration is a line between two-countries with in-between generation. Regarding onshore grid topology terms (e.g. Heuck and Dettmann, 1999), this can hardly be called a meshed network. Decker and Kreutzkamp (2011) classify it as a *tee-in connection*. As, however, the main challenges evolving from multinational offshore grids stem largely from regulatory questions between countries, they are in principle the same. It has therefore been decided that the visual wording of a *meshed offshore grid* should also comprehend this small-scale case. By contrast, it excludes networks that are connected to one country only, as suggested by Øyslebø and Korpås (2011) or Macharey et al. (2012). The latter source shows that an interconnection of German HVDC stations in the German Bight may be beneficial because the consequences of line failures are reduced remarkably.

3.1 A brief history

Offshore grids are a special, regional form of *Supergrids*. The first European supergrid proposal was put foreward by Gunnar Asplund, the HVDC technology development manager of ABB, in 1992. For an electricity system based on renewable resources, it suggests linking 200 GW of hydropower generation (mainly situated in Scandinavia, Scotland, the Alps) with 300 GW of wind generation (European west coast, Baltic Sea), 700 GW of solar generation (Mediterranean region incl. North Africa) and an unspecified amount of

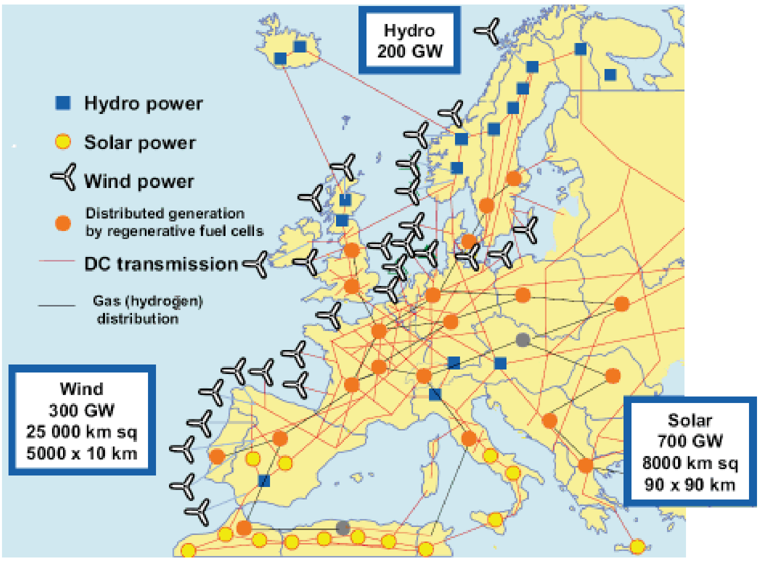

Figure 4: Original suggestion for an EU overlay grid, 1992 (ASPLUND, 1992)

distributed generation based by regenerative fuel cells. A "gas (hydrogen) distribution" and an HVDC overlay grid complement this vision (see figure 4). A quantitative analysis of an HVDC overlay grid was first done by CZISCH (2005) with a rather coarse geographical resolution (Europe, North Africa and the Middle East constituting a total of 19 regions). Based on 3-hour time steps, the optimisation yields an average electricity price of 4,65 Eurocent/kWh with existing technology and respective prices prevalent at the beginning of the century. This is based on a massive expansion in comparison with existing transmission lines between regions, e.g. more than 100 GW crossing the Pyrenees. Prohibiting all exchange between regions and introducing fuel cell generation to mitigate RES fluctuations leads approximately to a cost doubling.

The findings of TRIEB et al. (2006) confirm Czisch's main findings, focusing on the role of concentrated solar power in North Africa and the Middle East. In 2050, about 15% of European electricity demand could be covered by solar electricity imports transferred through interconnectors with a total capacity of 100 GW. Losses are at 10%, which is by far preferable to alternatives such as hydrogen storage based on electrolysis. This conclusion is again in line with CZISCH (2005). The main effect of TRIEB et al. (2006) is to have provided a sound scientific basis for the *DESERTEC* industry initiative, composed of scientific and private sector representatives from a number of possibly participating countries. The hitherto main contribution of this initiative is to have brought public attention to supergrids' possible contribution to an affordable electricity system based on RES generation (see figure 5).

As early as in 2001, a first more offshore-focused suggestion was put forward by Airtricity (AIRTRICITY, 2006). Referring to thoughts from the Western Danish TSO Eltra (ELTRA, 2004), WOYTE et al. (2005) conclude that "[c]ommon offshore cables bundling several

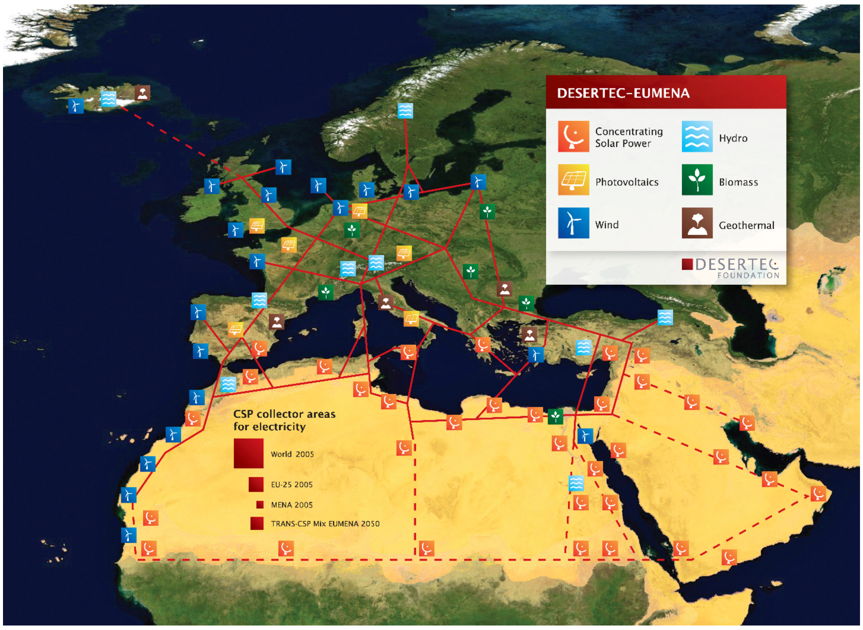

Figure 5: Illustration of the DESERTEC industry initiative vision for 2050 (DESERTEC Foundation, 2012)

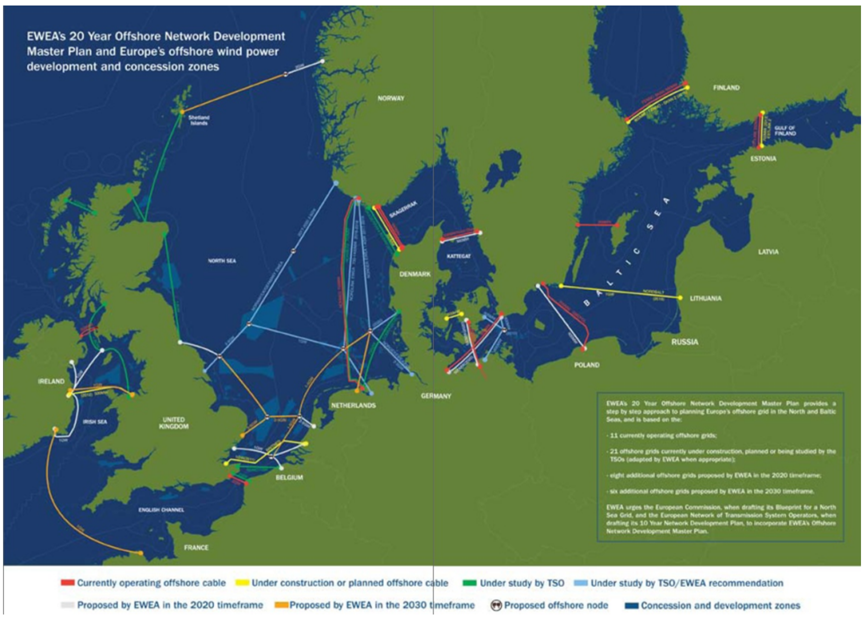

Figure 6: EWEA's 20 year offshore network development master plan (Fichaux et al., 2009)

wind farms [...] can become initial nodes of an international offshore grid". In comparison to the abovementioned more general supergrid proposals, AIRTRICITY (2006) proposal focuses on domestic energy resources only and is therefore not prone to geopolitical changes. The starting point should be a 10 GW foundation project, linking Great Britain with the Netherlands and Germany, which could later connect more countries. Mainstream Power suggested a similar three-country solution with Norway instead of the Netherlands (FICHAUX et al., 2009), thus giving Germany and the United Kingdom access to hydro storage resources. This approach is also pursued to a much larger extent by the GERMAN ADVISORY COUNCIL ON THE ENVIRONMENT (2010), showing that the hydro reservoir resources could serve as a storage and that way, rendering a 100% RES-based electricity supply in Central Europe considerably cheaper. However, this requires several dozen GW of connection capacity between Norway and Germany – an offshore grid.

Regarding a shorter time perspective from a wind-integration point of view, FICHAUX et al. (2009) draw on several other sources and identify several steps of an offshore grid: local/national grids constituting the first step, followed by a transition stage to a transnational grid and resulting in this. Already by 2020, this leads to meshed grid forms in the Baltic Sea (Kriegers Flak) and in the North Sea, which is extended considerably by 2030 (see figure 6). This second step focuses strongly on a meshed infrastructure in the Southern part of the North Sea, whereas the majority of previous interconnectors connect the UK and Central Europe with Scandinavian hydropower resources. These are the main suggestions for offshore grids from the private sector; for a literature overview as of 2012, see DECKER and WOYTE (2012) and sources therein. As it is also covering single projects, it should be noted that the single projects under discussion as of summer 2012 are Kriegers Flak between Denmark and Germany, CobraCable between Denmark and the Netherlands and connections between Great Britain, Denmark and Norway, respectively. The industry initiative "Friends of the Supergrid" is an active, institutionalised stakeholder promoting the idea of an offshore grid on behalf of various members with different backgrounds. Parallel policy developments are addressed in section 3.4.

A current overview of projects planned within the next 10 years is provided by ENTSO-E's Ten-Year Network Development Plan (TYNDP). It stresses a number of key factors, e.g. that responsibilities for building of an offshore grid should be clear, i.e. assigned to onshore TSOs, regulatory and planning obstacles need to be overcome and a harmonised cost recovery also of anticipatory investments is desirable (ENTSO-E, 2010). The 2012 update contains an overview of all projects considered within the next 10 years, including Kriegers Flak, CobraCable and a number of direct interconnectors between different countries (ENTSO-E, 2012b, ENTSO-E, 2012c), stressing the importance of the North Sea Countries' Offshore Grid Initiative (NSCOGI, see also section 3.4) in general and especially for a longer time period than covered by the Ten-Year Network Development Plan. The current ongoing work within NSCOGI is described in ORTHS et al. (2012), preliminary results indicating that capital expenditures could be reduced by 10% if an integrated instead of a radial connection concept is pursued.

3.2 Offshore grid topologies

In 2011, different optimisation approaches for the physical layout of offshore grids in Europe were published (see e.g. Trötscher and Korpås, 2011, and Decker and Kreutzkamp, 2011). The first paper's data background is from a remarkable offshore spatial planning project (Veum et al., 2011). A power market model and expected wind generation capacities at single nodes for 2030, the first model yields different grid topologies due to different cost ratios for substitutable electrical components, such as DC breakers and converter stations. DC breaker costs must not exceed one third of converter station cost to provide a competitive solution. Moreover, the results show that a meshed structure offers a net socio-economic benefit over a 30 year lifetime in the range of 10%. Interconnector utilisation increases from 45 to 70% by changing to a meshed grid. Another interesting result is computed by the comparison to a case without offshore wind: "the upper limit on the investment cost of wind power – for it to be viable in a socio-economic perspective – is €2.1m MW^{-1} installed." Regarding the moderate fuel price assumptions in the calculations as well as expected cost developments for offshore wind, this analysis confirms that investment even at far-offshore nodes are an option worth further investigation.

After having presented a work of a more conceptual nature in 2008 (see figure 7), an extended consortium (Decker and Kreutzkamp, 2011) computed different grid topologies for the North Sea until 2030. They distinguish two main strategies: the first one pursues a priority approach to *direct* interconnectors between countries. A meshed offshore grid could evolve from the interconnection of offshore hubs which were primarily intended for the absorption of offshore wind generation from multiple farms. The second main strategy is the *split* design, which starts from offshore generation hubs. Instead of connecting them to their homeland at full capacity, minor connections are erected to two neighbouring countries. Eventually, offshore hubs are meshed and the resulting topology resembles the one from the primary approach, yet with more offshore wind farms placed 'in' interconnectors. Over a time span of 25 years, the socio-economic benefit is 21 bn Euro for the direct interconnector case and 16 bn Euro for the split interconnector case, respectively. Due to less investment required, the split design has however a better benefit-to-CAPEX ratio Decker and Kreutzkamp (2011). Other interesting highlights from this study are that hub solutions for neighbouring wind farms remain in most cases beneficial even if one out of three wind farms is not realised, or if two out of three wind farms are delayed by 10 years. Finally, it needs to be mentioned that a major drawback of this study is that investment cost assumptions for grid assets are unpublished due to the high market concentration of network component suppliers.

3.3 Technical aspects of offshore connections

Offshore grids can partially be based on existing technology such as AC or HVDC technology. Meshed offshore grids at large distances from shore, however, would require the application of innovative concepts. This section provides a brief overview of the existing transmission technologies as well as of the innovative concepts under discussion for meshed HVDC grids between offshore wind farms and shores. For an overview of the topic that

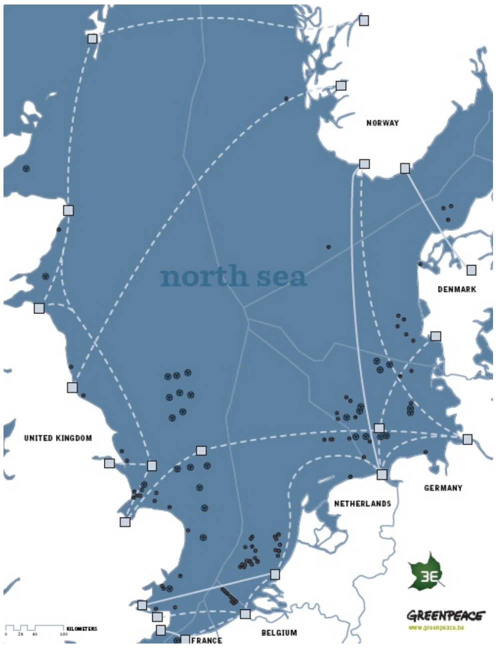

Figure 7: Offshore grid topology proposal (Woyte et al., 2008)

also includes cabling and generator type choice within wind farms, Ackermann et al. (2012) provide a good overview.

Alternating current (AC) is the common technology for electricity transmission at different voltage levels since the passing of the 19th century (Stoft, 2002), mainly due to lower losses for long-distance transmission. As cables have capacitative properties, reactive power needs to be compensated at regular distances. The maximum distance that can be realised from an economic point of view is at 70 - 100 km ENTSO-E (2011), although noticeably higher distances could be if a lower than customary voltage is used (Brakelmann and Erlich, 2010). Historically, only short subsea distances have been built, e.g. between the Eastern Danish and the Swedish sytem, or for offshore wind farms within a limited range from shore. The Danish wind farm Middelgrunden or, for a planned project, the German part of Kriegers Flak are examples of this practice. The North Sea and most other waters where meshed offshore grids could play a role in the future require HVDC technology.

The main components of High Voltage Direct Current (HVDC) are converter stations at the ends and single-core cables establishing the electricity circuit between them. The converter stations cause losses in the range of 1-2%, but this is compensated for large distances by the fact that line losses are commonly lower than for AC systems. HVDC systems are applied for large-distance onshore power transmission, e.g. in Canada, South Africa and China. In Europe, this technology represents the largest share of subsea electricity transmission. The historically seen capacities of approx. 300 MW, e.g. for the older

Skagerrak crossings, have been extended to 700 MW for the NorNed connection. Currently planned projects envisage higher voltages allowing yet more transmission of up to 1400 MW in Europe (e.g. NorLink/NorGer interconnector between Norway and Germany) and up to 7200 MW worldwide (ENTSO-E, 2011). Traditionally, HVDC connections are applied between asynchronous AC systems, e.g. the former Nordel and UCTE areas, and are subject to ramping constraints. The latter issue can be relieved with the installation of the voltage source converter (VSC) technology instead of the so-called 'classic HVDC' current source converters (CSC). VSC allows the exchange of spinning reserves and black start capability between systems. The new Skagerrak IV line between Western Denmark and Norway will permit sharing 10MW of primary reserves.

A VSC system is self-commutating, which is why it does not require a connection to a strong AC network. In addition, the converter stations are about 50% smaller, rendering it more attractive for offshore applications ENTSO-E (2011). Another advantage of VSC systems is that they are expected to support multi-terminal operation better than CSC systems, a key feature for meshed offshore networks. For more detailed technical information, the reader is referred to ENTSO-E (2011). The industry structure of HVDC system component suppliers is an oligopoly for most parts, historically even a duopoly for current or voltage source converters. This may be aggravated by lacking standardisation. Therefore, if large multiple-terminal systems are envisaged for the North Sea, increased standardisation could allow a 'plug&play' combination of components from an increased number of suppliers. The standardisation issue has been discussed in the industry for a number of years ENTSO-E (2011), which is why the author expects that this challenge will at least be partially solved before components for multi-terminal offshore grids need to be ordered. At the same time, the economic growth namely in vast countries as China, India and Brazil leads to a number of HVDC systems being installed in these countries, possibly supporting manufacturing capabilities of local companies.

Regarding the capacity limits, it is doubtful that further considerable increases beyond the 1400 MW mentioned above are useful. The reason for this are the requirements of the existing national onshore networks: the largest single generators in Western Europe are in the range of 1.5 GW, implying that a corresponding amount of spinning reserves is required in case of a failure. This can be regarded as an upper limit for the connection of new generation units or interconnectors. For the Irish Sea, this argumentation has led to the suggestion of several parallel HVDC networks (Elliott, 2011). Such a modular approach can also facilitate the connection of several successively erected offshore wind parks because problems with one infrastructure do not add risks in the process of realising following projects. For more information on the ISLES project and its suggestions for the Irish Sea, see section 3.6.3 or ISLES (2011a).

Rudion et al. (2010) develop a four-country benchmark test sytem for a meshed North Sea offshore grid that can be used for future electrical calculations on a standardised basis. Based on it, a so-called observer-based management system has been implemented (Rudion et al., 2011). The optimal slack position in the multi-terminal HVDC system is then computed with energy market input data. In other words, the optimal voltage-'leading' HVDC terminal in the HVDC system is determined for every time step to keep the voltage in the whole system within desired boundaries. The time horizon for these slack changes is hourly and energy market as well as wind generation are input parameters. Rudion et al.'s 2011 work can therefore be categorised as the techno-operational counterpart of some of the market-operational issues addressed in this thesis.

3.4 Legal and policy aspects

Also from a legal point of view, establishing an offshore grid poses a number of challenges. All North Sea countries have ratified the UN Law of the Sea Convention (UNCLOS) and established an exclusive economic zone (EEZ), giving them the right to use the RES energy resources (Roggenkamp et al., 2009). Moreover, the UNCLOS ensures the right to build cables within or across an EEZ, i.e. transit cable permissions cannot be opposed fundamentally. The regulatory combinations possible in an offshore grid lead to different national regulations applying. The benchmark case, the connection of an offshore wind farm to its national shore, may be rendered more difficult by distinguishing onshore and EEZ activities. For other combinations, such as the connection to a foreign country or to a meshed offshore grid, the single interconnectors would be regarded as transit cables. A tee-in connection is not explicitly accounted for in current EU legislation, which is why national regulations would have to specify provisions (Roggenkamp et al., 2009). In addition, it is unclear which grid codes would apply in such a case or the case of an offshore wind farm's connection in an EEZ to another country (Woolley et al., 2012). They also elaborate on how the USA, which have not ratified UNCLOS, use their federal jurusdiction on their outer continental shelf. Müller (2012) suggests that EU legislation can also apply offshore if this is not in conflict with general international law. It could thus be shaped in a way that it is favourable for the development of a meshed offshore grid.

In the EU, industry initiative developments were supported by political and administrative representatives as well as by transmission system operators over time. European Parliament and Council (2006a) deals with priority projects for Trans-European Energy Networks, namely "establishing/increasing electricity interconnection capacities and possible integration of offshore wind energy" in a number of regions. This formulation addresses interconnector capacities also with regard to offshore wind, but does not state explicitly that interconnectors could use offshore wind generation sites as intermediate offshore hubs. Moreover, the role of a European Coordinator as a facilitator for single projects is established in this document. The former German Vice Minister of Economic Affairs, G. W. Adamowitsch, assumed this role in 2007 (Adamowitsch, 2008). Following EU legislative action promoting the idea of an offshore grid is European Commission (2008). Out of six priority infrastructure actions proposed, the "Blueprint for a North Sea Offshore Grid" to be developed is the only one limited to the electricity sector. Together with other regional initiatives in the Baltic Sea and Mediterranean, it could constitute the main "building blocks of a future European supergrid". A more concrete proposal, naming single projects, was put foreward within three months after this general strategic outline. The proposal gives a "financial stimulus" to the energy sector as part of the recovery plan in the light of the financial crisis European Commission (2009), inter alia envisaging European community contributions to international grid reinforcements, offshore wind projects and combined grid solutions at Kriegers Flak and the “modular development of [an] offshore grid” in the North Sea. The latter two contributions are budgeted with 150 Mill. Euro and 165 Mill. Euro, respectively (European Parliament and Council, 2009b). Since then, more detailed plans for the North Sea offshore grid are under development by a number of research projects and industry stakeholder consortiums.

The North Sea Countries’ Offshore Grid Initiative (NSCOGI) was launched at the European Union Energy Council in December 2009, signed by Belgium, Denmark, France, Germany, Ireland, Luxemburg, the Netherlands, Sweden and the United Kingdom, with Norway joining two months later. A Memorandum of Understanding from December 2010 (Ministers of the North Sea Countries’ Offshore Grid Initiative and the European Commissioner for Energy, 2010) acknowleges the possible multiple benefits of an offshore grid and establishes a committee structure as well as three working groups on grid configuration & integration, market and regulatory issues and planning and authorisation procedures which are designated to finish their work plans until December 2012.

3.5 Stakeholder roles

This section turns towards the division of responsibilities among the main actors involved in offshore grids, as this has implications on their incentives during planning, building and operation phases. The main actors are transmission system operators, wind park planners and regulatory authorities, e.g. for maritime spatial planning and permission procedures and for energy sector regulation. Supranational bodies involved in this are namely the Agency for the Cooperation of Energy Regulators (ACER), the European Network for Transmission System Operators for Electricity (ENTSO-E) and linked, more concrete initiatives as NSCOGI. However, both the erection of connections from offshore wind farms and international interconnectors is subject to national regulations. Reflecting a wide range of regulatory options with regard to the national connection of offshore wind farms, Levêque et al. (2012) focuses on Germany, Sweden and the United Kingdom. Slightly differently, this chapter gives a short overview of responsibility distribution for three selected North Sea countries: Denmark, Germany and the United Kingdom. These are key countries for the development of meshed offshore grids.

In Denmark, the connection responsibility is with the state-owned TSO Energinet.dk. The climate and energy minister acknowledges the subsea water cable plans and in the following, the costs of the new interconnector and its converter stations are levied onto transmission system tariffs to be paid by consumers and producers. The economics of connections between different electricity market areas are based on socio-economic calculations. Projects being built or under investigation cover an additional interconnector between Western Denmark and Norway, Kriegers Flak, CobraCable to the Netherlands and a connection with Great Britain. Energinet.dk thus plays a key role at least in the early stage of offshore grid developments.

In Germany, it lies within the responsibility of the coastal TSOs TenneT TSO GmbH and 50 Hertz Transmission GmbH to connect offshore generation. They do this within the regulatory and spatial planning frameworks set by the involved regulatory authorities, e.g. with regard to combined connections of several wind parks (see e.g. BSH (2012)). TenneT is in charge of all North Sea projects and 50 Hertz in charge of virtually all Baltic Sea projects. In contrast to Denmark, the companies are completely or partially owned by foreign TSOs, namely the Dutch and Belgian ones which are fully or partly publically owned. The main focus of the public discussion is on TenneT activities in the North Sea, where the company is expected to connect several GW of new generation capacity within a short time span. The first connections, among them offshore hubs for several offshore wind farms, are established or under construction. Due to a number of bottlenecks, TenneT announced that they will not be able to meet the regulatory requirements in the future (TenneT TSO GmbH, 2011). At the time of writing, it is unclear how this problem could be overcome; a German offshore TSO, a wider financial base and different approaches to liability questions are under discussion.

In the United Kingdom, the single offshore wind parks used to be responsible for their connection to the onshore transmission system. Such an approach inherently disregards cost savings through a coordinated hub approach. The British regulator OFGEM established the *Offshore Transmission Operator (OFTO)* scheme in 2009, expecting that a competitive tendering process for offshore connections would lead to a more efficient solution in parallel to onshore grid operation. This tendering approach included also already existing offshore connections, forcing existing offshore wind parks to sell their transmission assets. The OFTO regime is currently under revision (Ofgem and Department of Energy and Climate Change, 2012). Core issues being addressed cover anticipatory investments for additional capacity to be installed in the vicinity and associated transmission use of system charges for the offshore generators, which are yet undefined for offshore hubs. Agreeing to offshore hub connections can therefore imply an additional risk for offshore generation project developers.

Weissensteiner et al. (2011) regard the cost-effectiveness of support and grid connection schemes. They draw on the concept of *deep* versus *shallow* connection charges, the first one meaning that a new generation unit has to pay for all related connection and network reinforcement costs, whereas the second one means that only connection costs to the nearest network node need to be paid for (Ropenus et al., 2011). This concept is extended by *super-shallow* connection charges, representing that also the exclusive network assets including the offshore substation are financed by network operators. Considering a number of offshore wind park projects with rising marginal costs, Weissensteiner et al. (2011) argue that connection costs are roughly proportional to generation installation costs. If a shallow connection regime is introduced and grid connection costs thus are included in offshore wind support, this gives an additional producer surplus to all other projects with lower marginal costs. If alternatively the super-shallow connection regime is introduced, this producer surplus is reduced and connection costs are implicitly paid for by all parties paying use-of-system charges. The super-shallowish connection approach is therefore more cost-effective for these final consumers. However, the argumentation is based on a number of assumptions, inter alia a uniform support level for offshore generation (as applies in the United Kingdom). For Denmark with project-specific tendering and Germany with increasing support duration depending on water depth and distance from shore (BMU, 2011), the assumptions do not hold and thus, the cost-effectiveness argumentation does not qualify. A coordinated grid development by the national TSO is however desirable for other reasons such as the erection of offshore hubs. As this reaches beyond the mere connection obligation for TSOs, it would be difficult to base investment into the infrastructure primarily on super-shallow connection regimes, as critically discussed in Tscherning (2011).

For the sake of completeness, *merchant transmission investment* needs to be addressed in this section. This concept represents the erection of new interconnectors by non-TSO entities (Joskow and Tirole, 2003). Regulation 714/2009 (European Parliament and Council, 2009c) stipulates that such projects may be exempt from some commonly applying rules for investment, provided inter alia that this exemption fosters competition and the risk level of the project is such that it would not be realised without the exemption. An overview of regulatory practice for electricity interconnectors by Cuomo and Glachant (2012) shows that different measures were taken in case that the fulfilment of all criteria could not be ensured. Egerer et al. (2012) addresses merchant transmission investment in the context of offshore grids, assuming that new direct interconnectors should be financed by merchant transmission investment. They conclude that this will hardly be profitable. As wind generation in meshed solutions or the integration of an offshore wind park into a single interconnector cannot improve this situation, the author regards it as useful to limit the scope of this work to wind operators and TSOs. Nevertheless, some of the argumentation applied to TSOs would in theory also extend to merchant transmission investors (cp. Paper III), although this constellation seems unlikely.

3.6 Practical cases in different geographical areas

3.6.1 North Sea

The North Sea is the main focus region for offshore wind power and meshed offshore grids. Historical suggestions on meshed offshore grids are chiefly about it, which is why most of the examples and maps above deal with it. These points are not repeated here for brevity reasons. Instead, additional and and more specific issues are addressed in the following.

A core argument for offshore grids in general are spatial levelling effects of the fluctuating wind resource. Most of the respective quantitative analysis are about the North Sea. A publication partly based on the early suggestions by Airtricity (Airtricity, 2006) is Hurley et al. (2007). Taking representative wind speed time series for several European locations, they compute spatial smooting effects and conclude that including all considered sites, "two-thirds of all load factors [are] between 30 and 70 per cent of total capacity". The sum of generation and transmission capital cost from offshore wind at main European load centres is estimated to be in the same range as for low to medium onshore wind sites. The spatial smoothing effect for the North Sea is illustrated in figure 8 for a short

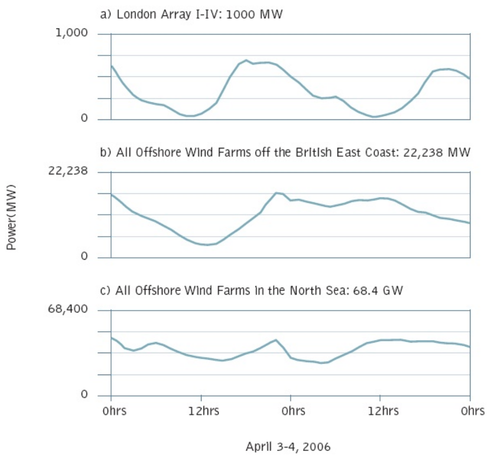

Figure 8: Power output of offshore wind power over two days (Woyte et al., 2008)

interval. Analyses and illustrations on spatial levelling effects covering a 5-year period can be found in Brodersen et al. (2009). Generally speaking, they confirm the impression of considerable spatial levelling effects from figure 8.

The TradeWind project was the first large-scale academic project addressing inter alia the North Sea offshore grid. Its calculations are based on simulations with the Power System Simulation Tool (PSST) tool, assuming a perfect European power market without the exercise of market power, no unit start- or stop-costs and perfect foresight. The capacities displayed for 2030 in figure 9 result from an iterative approach, yielding a 'remarkably lower' system operation cost (Korpås et al., 2008). The extended offshore network leads to less wind curtailment of approx. 2% instead of 3% under radial connections, although this share still exists mainly due to congestion in the onshore hinterland.

The most concrete case which has been investigated is about the CobraCable (Decker and Kreutzkamp, 2011). It is a transmission project between the Netherlands and Denmark and passing by the German offshore wind farms of Butendiek (400 MW) and a German wind farm cluster of 1300 MW. All analysed combined solutions are preferable to the individual national connection of Butendiek and the cluster, the most beneficial being the inclusion of the cluster into the cable with a separate connection between Butendiek and Germany. This is mainly based on the capacities and spatial levelling effects, i.e. that the cluster does not suffer from its high correlation with remaining German wind generation and the associated merit-order effect (see section 5.4). Regarding the current regulatory setup and the division of responsibilities between stakeholders, the author does not regard it as likely that a combined solution will be implemented.

The main work in the field (Decker and Kreutzkamp, 2011) is complemented by several academic papers, namely Bettzüge et al. (2010), Egerer and Kunz (2011) and Egerer et al. (2012). The first paper assesses investment cost for three connection capacities (2.5-7.5 GW) that could be installed between Norway at the Northern end and

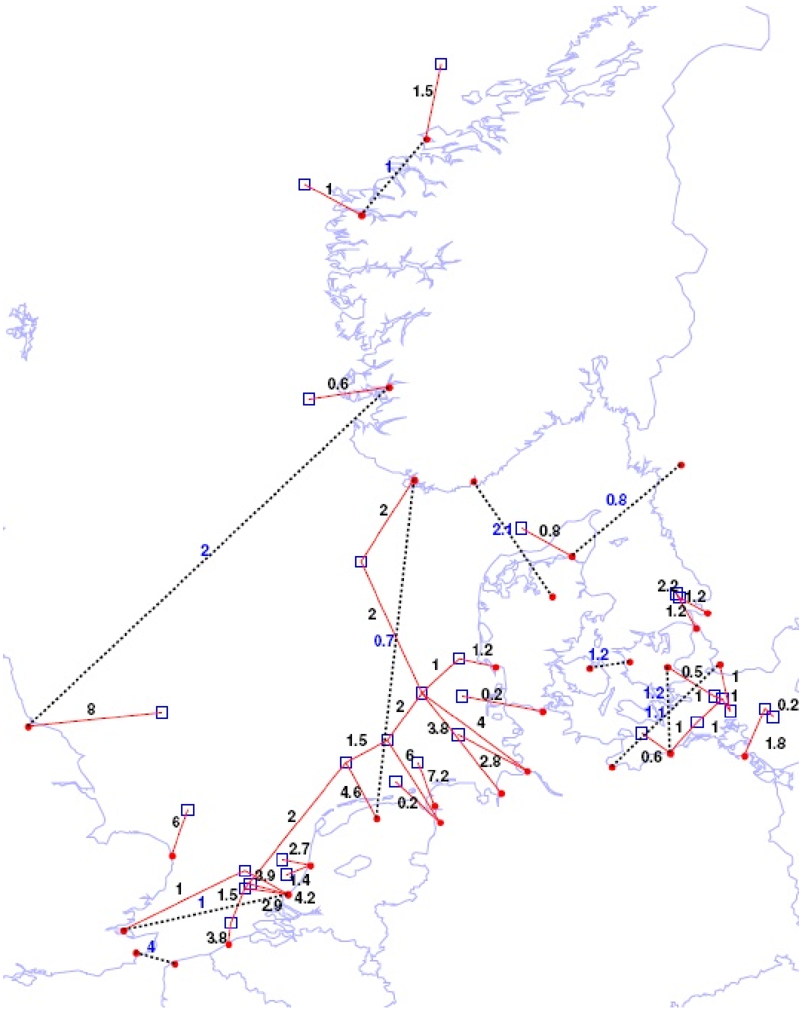

Figure 9: Capacities (GW) of HVDC connections in the North Sea and Baltic Sea (extract). Values in blue: direct interconnectors (Korpås et al., 2008)

Germany, Netherlands or France at the Southern end. They conclude that the smallest capacity case has positive net welfare effects for all considered connections, whereas the largest is only beneficial for the connection between Norway and Germany. Egerer and Kunz (2011) address possibilities for merchant transmission investment in the North Sea. Based on congestion rent computations, they find that most of the connection will have to be built as regulated investments and only few could be built as merchant interconnectors. These findings build on an earlier version of Egerer et al. (2012), who furthermore address national welfare reallocation based on a 'trade' and a 'meshed' grid topology scenarios. The UK, Norway and the Netherlands benefit in every case, whereas the results are neutral or partly negative for the other countries.

An interesting case study performed by Weigt et al. (2010) addresses the hinterland connection question for Germany. Most other sources in this thesis deal with connections of offshore wind power to shore or with supergrids at a macroscopic level, whereas Weigt et al. (2010) suggest to connect offshore wind farms to distant onshore load centres in Germany. However, their analysis does not include possible line failures, nor are the offshore generation sites in the North Sea part of a meshed offshore grid. Regarding that the main constraint may be the erection of hinterland connections, it seems a better approach to integrate them in a meshed (possibly HVDC) network to use them also when the connected offshore wind farm's generation is low.

3.6.2 Baltic Sea

The main direct interconnections between countries to be added in this decade are between Estonia and Finland as well as between Sweden and Lithuania, both with 650-700 MW of capacity (ENTSO-E, 2012a). The only current project involving wind energy is called Kriegers Flak which could be followed by several other combined solutions later (Decker and Kreutzkamp, 2011). At Kriegers Flak, both Denmark and Germany plan to build offshore wind farms at this offshore border triangle of the two countries with Sweden. The EU decided to grant support of 150 Mill. Euro to a combined solution (European Council (2009), Energinet.dk (2010)), which can be interpreted as a measure to support innovation for large-scale RES grid integration (Meeus and Saguan, 2011). Both a pre-feasibility and a feability study (Energinet.dk et al., 2009, E-Bridge, 2010) show that the project is beneficial, although this seemingly clear conclusion from the latter report could be discussed in the light of the data presented in it. Alternative analyses with the WILMAR model confirm the finding that a meshed solution at Kriegers Flak could be beneficial (Schröder et al., 2010, and Paper V). Kriegers Flak could hence become the first case where international power transmission is combined with generation from even two countries. After prospective realisation by 2017 (ENTSO-E, 2012b), this complex technical and regulatory constellation could serve as an example especially for the large-scale plans in the North Sea.

3.6.3 Irish Sea

Both Ireland and Great Britain are island systems with limited interconnections. Therefore, they face more severe constraints for wind integration than the continental European system due to frequency stability and spinning reserve requirements (EirGrid and SONI, 2010). Moreover, facilitating wind integration by onshore grid reinforcements faces such difficulties that subsea cables parallel to the shore are regarded as a feasible alternative (see ENTSO-E, 2012b, and ISLES, 2011a, for examples). ISLES (2011b) illustrates in detail how a meshed offshore grid could be modularised. The outage of a huge HVDC network would endanger system security especially on Ireland or require disproportionally large reserves. Splitting the offshore grid into several HVDC networks reduces this risk. In addition, building several smaller, but independent networks reduces their interdependency. This is an advantage both from a technical and a financial point of view.

3.6.4 US East Coast

Considering the optimal relation between installed wind and wave capacities and a combined interconnector, Stoutenburg and Jacobson (2011) show that the required connection capacity can be reduced by 8%. Their computations are based on a Californian case study and include curtailment during hours with simultaneous maximum output of both technologies.

A possible offshore grid along the US East Coast has received some media attention during 2010 and 2011, mainly due to the fact that Google is one of the financial investors involved. It is envisaged to link 6 GW of offshore generation aligned along the US East Coast to shore and among each other. Dvorak et al. (2012) analyse this suggestion from an academic perspective for 2 GW of wind capacity. Four wind sites were chosen from a selection to yield a high capacity factor, smoothed overall generation and connect different electricity systems along the coast. Their analysis draws interesting results based on wind resource characteristics, but does not extend to an economic optimisation demonstrating the advantageousness of their proposal. By contrast, Ibanez et al. (2012) pursue such a co-optimisation approach of wind siting and accounting for transmission integration costs. They show how up to 54 GW of offshore wind in the US could be distributed, mostly along the east coast, until 2030.

3.7 Contributions of the papers to the research field

The papers I to VI in the appendix deal with the integration of offshore wind energy by offshore grids. As papers I, II, V and VI are closer to the topics of support schemes and electricity markets discussed in the following chapters, their contributions are also mainly addressed there (see sections 4.3, 5.5). Here, the focus is on the case studies about Kriegers Flak (Paper V, *(The impact of an offshore electricity hub at Kriegers Flak on power markets)* and the comparison of on- and offshore power storage in paper VII *(Compressed air energy storage in offshore grids)*.

The case study on Kriegers Flak applies the WILMAR Joint Market Model to the three-country solution and thus, complements other studies briefly presented in section

3.6.2. It shares hence some characteristics with Bettzüge et al. (2010) who did similar calculations for larger connection capacities in the North Sea, but with a deterministic model. Main findings are that minor electricity price decreases can be expected in Germany, whereas Denmark would experience slightly and Sweden considerably (0.8 Euro/MWh) rising average prices. The computed socio-economic benefits are rather low in comparison to E-Bridge (2010), but still in a range that especially the largest option seems promising. Moreover, the duration flow curve patterns are remarkably similar. The case study is the first one assessing both congestion rents under a) nodal pricing and b) if national offshore transmission is transmitted onshore for free, as it is the case in the benchmark situation (see section 3.5 or Paper I). By this provision, congestion rents are reduced to between 41% and 62% of the calculation under nodal pricing. The decisive question for an investment decision is therefore whether the project should be judged from a socio-economic or a private-economic point of view.

Paper VII *(Compressed air energy storage in offshore grids)* is also a case study with the WILMAR Joint Market Model for the year 2015, but with a better representation of bottlenecks within countries. The basic idea is to investigate offshore storage in comparison to alternatives. It is shown that there is a considerable overlap between offshore wind farm sites in Germany and salt formations under the sea, allowing for offshore (adiabatic) compressed air energy storage (CAES). Such a combined generation and storage site carries some characteristics of projects discussed as 'EnergyIslands' (see e.g. KEMA (2012)). The cases compared are illustrated in figure 10: a CAES facility placed onshore, offshore or replaced by an interconnector of similar capacity to hydro reservoir resources in Norway. From an operational perspective the interconnector option is the most beneficial one, followed by onshore CAES storage. Offshore storage has two drawbacks: 1) the interconnector blocks it from contributing to a system with high demand. In a nutshell, this system could benefit from full interconnector capacity imports *plus* storage generation if storage was placed onshore. 2) The offshore CAES unit cannot contribute to onshore spinning reserves. The operational mode of the onshore CAES unit belongs to the most interesting results of the simulation: both the compressor and generator unit operate simultaneously. This has also been demonstrated in other sources (see e.g. Lund et al., 2009), but with a different optimisation approach on the spot market for a conventional non-adiabatic CAES plant. Their main operation mode is hence to serve as a spinning

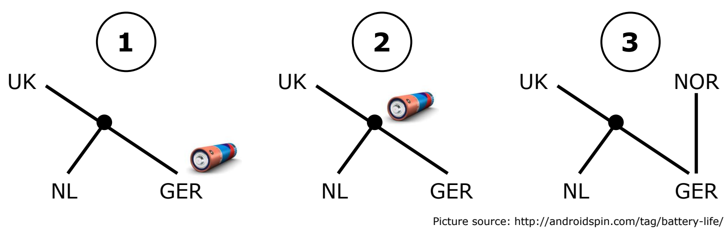

Figure 10: Cases compared in paper VII

reserve provider that occasionally benefits from spot market price differentials. Taking a private-economic perspective, reserve payments constitute an important part of a private-economic business case (Lund and Salgi, 2009). In the long term, this operation and remuneration mode for conventional or adiabatic CAES plants could play a role for energy systems in Northern Europe with a very high share of RES generation. This type of local storage may be a more feasible option that erecting large amounts of transmission capacity through densely populated regions.

4 Support schemes

4.1 Overview

Support schemes for RES serve different means such as supporting CO_2-free electricity generation, technology development, contributing to security of supply and local job creation by being more labour-intensive than conventional power plants (cp. section 2). Regarding their contribution to mitigate climate change, they complement CO_2 emission caps and associated trading to promote technologies that may become economically viable in the future. This does not lead to a cost-efficient CO_2 reduction strategy at the moment; in fact, the comparatively high RES support levels interact with CO_2 quota prices and electricity prices (Morthorst, 2003a Jensen and Skytte 2003, Rathmann, 2007). Instead, it supports RES technologies which would not be develop only under a CO_2 cap regime due to different market imperfections, namely subsidies for fossil fuels and the risk associated with deploying a new technology.

Operating support schemes can be rougly categorised into *price-based* and *quantity-based* systems. Assuming a RES cost curve, policymakers can either set a price or a quantity signal (see e.g. Menanteau et al. (2003) for an early discussion on the subject). The other parameter adjusts accordingly and, assuming perfect market conditions and the absence of uncertainty, both schemes have equivalent outcomes (Weitzman, 1974). As the cost curve is not known in reality, price-based support schemes can result in over- or underdeployment of a technology, possibly with large amounts of support required (as illustrates the historical case of PV in Germany - see e.g. Frondel et al., 2010). Setting the quantity results in an unknown support level for RES generation, exposing single projects to a higher level of uncertainty (Mitchell et al., 2006, Kitzing et al., 2012). This section gives a brief overview of the most relevant support schemes for generation based on RES; other methods that may be applied in parallel, such as investment support, research funding and tax credits, are beyond the scope of this work.

4.1.1 Price-based support schemes

Feed-in tariffs grant a fixed rate (e.g. Euro/MWh) to eligible generators for a predefined duration. They are typically differentiated according to the generation technology and sometimes also according to their capacity, site criteria or other specifications. Feed-in tariffs are usually combined with priority access to the grid, i.e. that they can always generate. The interaction with electricity markets is handled by an agent, typically the TSO: supported generation is sold in electricity markets. The resulting difference between the market price and the fixed-income support level is incurred via a levy charged to consumers. Thus, depending on market price fluctuations, the magnitude of the support levy can vary (see the left part of figure 11).

Price premiums are a variation of feed-in tariffs where the plant owners themselves are responsible of marketing their generation in electricity markets. For most RES technologies, this comprises meteorological generation forecasts. In one possible design option of price premiums, a fixed premium is granted on top of the power market price (figure 11, right).

This has the effect that the expected power market prices impact the investment decision considerably, while generation is adjusted to market prices as far as possible. This is also why price premiums are commonly considered a policy tool for more mature RES markets. In another possible design option, a variable premium is paid (figure 11, left): it corresponds to the difference between a guaranteed income level and the (average) spot market price. This option hence combines the incentive for market-adjusted generation schedules with a fairly certain income level. For both options, the price premium expenses are incurred among customers as for the feed-in tariff.

4.1.2 Quantity-based support schemes

A *tradable green certificate* scheme establishes a separate market: producers or consumers (i.e. respective retailers) are mandated that a certain share of their electricity needs to come from RES. Each RES-generated energy unit entitles its operator to receive a RES certificate. As under price premiums, their income is thus composed of electricity sales and an additive component for its 'green' properties. The above-mentioned mandated party can prove its quota fulfilment by either generating RES-based electricity – and associated redeemable certificates – itself or by acquiring them on the market. In a technology-neutral system, this leads in theory to a least-cost deployment of renewable resources with existing technologies if proper market design, e.g. sufficiently high penalties for compliance failure, is implemented. Technology differentiation can be achieved by granting more tradable green certificates to an eligible RES technology than to others. This approach supports especially rather immature technologies, but is inherently detrimental to achieving a certain RES generation at the lowest cost possible.

Tendering typically means that competitors bid for a predefined amount of technology-specific generation capacity, e.g. offshore wind in a narrowly defined area. The bids may be judged according to different selection criteria such as least cost. In this example, the bidders with the lowest cost, in total covering the desired capacity, are awarded long-term contracts (Menanteau et al., 2003). The financial criterion could in practice be the required feed-in tariff or price premium level (see above). Contract design should be such

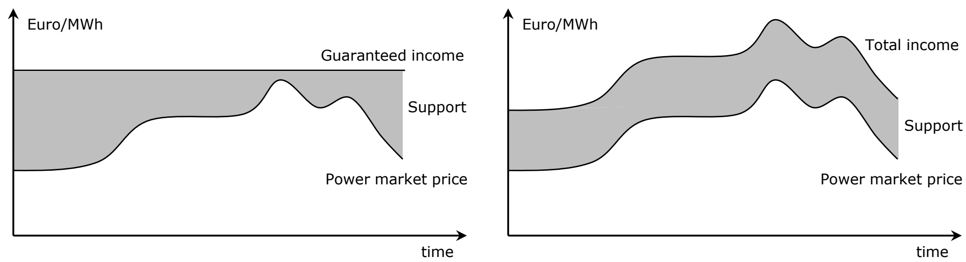

Figure 11: Price-based support: Fixed income with variable support (left) or variable income with fixed support (right)

that awarded companies will not retreat due to changed market environments, thus leaving the awardee with less than desired RES generation.

Regarding the interplay with electricity markets (cp. section 5), Hiroux and Saguan (2010) find that a price premium is likely to incentivise wind park operators to react to market signals while being sufficiently risk-absorbing. An application overview of the support schemes is certainly beyond the scope of this thesis, but an interesting general overview with comparisons with regard to effectiveness and efficiency can be drawn from e.g. Steinhilber et al. (2011). The following part focuses on currently existing support schemes for offshore wind power.

4.2 Practical examples: Support for offshore wind

Table 1 provides an overview of support schemes in the major Northern European offshore countries that play a role in meshed offshore grid plans. The German law leaves a number of choices to offshore project operators; they can choose between a feed-in tariff scheme and a price premium scheme with a variable premium, ensuring the same overall income as for the feed-in tariff plus a self-marketing add-on. In addition, they can choose receiving a higher income in exchange for a shorter support period. Tradable quota schemes are implemented in Norway and Sweden as well as in the United Kingdom. The Scandinavian system is not differentiated according to technologies, which is why comparatively expensive offshore wind capacity will hardly be erected under it. Contrarily, the British Renewable Obligation Certificates (ROCs) scheme grants 2 certificates per MWh generated offshore, in comparison with 1 certificate for onshore generation. The by far most widespread support mechanism is tendering for pre-defined sites. The required feed-in tariff forms part of the French tendering procedure (Berthelemy, 2012), whereas the required overall income under a premium scheme constitutes the Danish criterion. The tendering mechanisms are hence project-specific variations of the support schemes which are generally applied in these countries. Green and Vasilakos (2012) recommend the application of tendering-based feed-in tariffs for the support of offshore wind.

4.3 Contributions of the papers to the research field

The interaction of support schemes and offshore grids has hardly been addressed in the past. In general, all of the above-mentioned support schemes are within the frame-

Support mechanism	Countries
Feed-in tariffs	Germany, Ireland
Price premiums	Germany
Tradable quotas	Belgium, Norway & Sweden, Poland, United Kingdom
Tendering	Denmark, France, the Netherlands

Table 1: Support mechanisms for major offshore wind markets in Northern Europe

work stipulated by the Directive 2009/28/EC (European Parliament and Council, 2009a), which also lays the framework for joint support between countries. Three categories for joint support are distinguished: (a) statistical transfers, allowing a transfer of excess RES generation from one country to another, (b) joint support schemes or (c) joint projects, where inter alia the attribution of RES generation to Member States have to be defined. Notably Klessmann et al. (2010) elaborates extensively on design options for these tools, but does not look at offshore grids. There are various possibilities how the price for a transfer between countries could be determined, and one of the crucial questions could be if and how indirect effects, such as network connection costs and interaction with electricity markets, could be accounted for. Paper IX draws on some of this argumentation and addresses possible combinations of support schemes and cooperation mechanisms for offshore wind energy. Especially due to offshore grid plans, offshore wind energy might be a good starting point because it inherently requires international cooperation. It suggests that tendering for joint projects is a practical combination for the short term, whereas a tradable quota scheme for the whole North Sea region might be an option for achieving post-2020 targets which are yet to be defined.

The Papers I *(Interconnector capacity allocation in offshore grids with variable wind generation)* and III *(Electricity market design in offshore grids – strategic incentives under different regulatory regimes)* are based on an electricity market design aspect related to support schemes: balancing responsibility and its attribution to different actors, i.e. to TSOs under feed-in tariffs and to the OWF operators under other schemes as price premiums. It should be noted that this refers to *operational* aspects, i.e. a tendering procedure where a feed-in tariff or price premium level are the criteria has equivalent operational effects than these. Paper I is the first detailed study demonstrating that the incorporation into an offshore grid is not necessarily neutral for an OWF operator because balancing possibilities with its 'home country' can be limited due to interconnector congestion. Paper III generalises the argumentation and presents beneficial strategies for individual actors under different regulatory constellations. The co-optimisation of wind balancing and congestion management in the hands of the TSO reduces such strategic incentives which can lead to socio-economically suboptimal outcomes. As wind balancing is typically within the responsibility of the TSO under feed-in tariffs, these are preferential to more market-price exposing support mechanisms in meshed offshore grids. However, the combination of balancing responsibility and feed-in tariffs could also be separated; price-premium or tradable quota schemes exposing OWF operators to spot market prices only are also possible, leaving the operational balancing part to TSOs.

The notion supporting feed-in tariffs is also advocated in Paper XI *(Joint support and efficient offshore investment: market and transmission connection barriers and solutions)*, linking regulatory-operational aspects to investment incentives in offshore grids. In contrast to the two aforementioned papers, its argumentation is based exclusively on spot market prices and disregards balancing issues. The benchmark case is a feed-in tariff for offshore wind generation in one market, yielding a certain internal rate of return to the project owner. A connection is only established to this one home market as it is customary under super-shallow connection charges, leaving the TSO without congestion rents. This is contrasted with a price premium case giving the same average return. The price premium support is then applied in a number of regulatory constellations, *inter alia* extending the number of connected markets up to four and assuming a home country affiliation, a primary access right of the offshore generation node to neighbouring markets or, alternatively, assuming it to be in an neutral offshore hub. These constellations are partially based on the Papers I and III. The most noteworthy results are that the benefit of additional markets is decreasing for the OWF operator in the home country case, positive, but not steadily growing for the primary access case and mixed for the offshore hub case. Due to the redistributive nature of the setup, TSO's congestion rents mirror these outcomes. The consequences of line failures are mitigated by additional interconnectors, which is according to expectations and in line with MACHAREY et al. (2012). Finally, a sensitivity analysis on interconnector capacities shows that minor increases of one line's capacity only yield minor changes, whereas doubling the capacity gives a considerably changed picture. This is due to the fact that this virtually changes an even-number interconnector setup to an odd-number setup, giving a different pricing constellation for the intermediate offshore hub.

The study provides a novel approach to offshore grids and succeeds to highlight resulting investment incentives from different regulatory constellations. From a methodological point of view, the line failure simulation approach used in some cases requires further validation; the combined Poisson/normal distribution approach differs from alternative methods as e.g. used by MACHAREY et al. (2012). Adapting their approach would however require the simulation of whole investment periods covering 20 years instead of a Monte-Carlo analysis based on a large number of single operation years. Quantitative results may change, but the qualitative consequences are expected to remain the same if this extension was applied as a part of future research.

5 Electricity markets

In Europe, the operation of the electricity sector is mostly coordinated by electricity markets. Their operational procedures have consequences for the behaviour of different stakeholders involved, and operational aspects have consequences for investment decisions. This section gives a brief overview of their main features first. Then, the part on *Wind in liberalised electricity markets* addresses the main integration questions of wind energy before the final part highlights how the studies presented in the Papers contribute to this field.

Liberalised electricity markets evolved from different historical backgrounds and have very different characteristics between continents and countries. They all share the distinctive feature that real-time markets cannot give the main signals, as opposed to goods that can be stored in a fairly economic way. System security requires earlier planning of unit commitment and dispatch schedules especially for thermal units and with regard to transmission constraints, while keeping sufficient contingency reserves. These core requirements have been translated into different market designs across the world: in the United States, a nodal pricing approach giving dispatch signals to single power plants in steps of 5 minutes is applied by an Independent System Operator. This approach implicitly accounts for regulating reserves as well. As the focus of this work is predominantly on Europe, the following elaborations are limited to Western European market design and only refer to alternative approaches where useful. A highly detailed up-to-date review for most Western European markets is provided in Barquín et al. (2011), whereas Rebours et al. (2007a) and Rebours et al. (2007b) address ancillary services also for a number of non-European countries. Capacity markets are currently under discussion to provide investment incentives along with energy markets. Due to its fluctuating nature, wind energy is not among the qualified technologies in any of the suggestions and therefore, the focus remains in the following on energy markets and balancing aspects.

The Nordic power exchange NordPool can be seen as a role model for most European electricity exchanges today: the day-ahead market with an hourly structure, following successive correction markets and implicit capacity auctions between regions as main characteristics are applied in most of Western Europe today. The origins of NordPool are therefore even more interesting: its predecessor was founded in 1970 as a means to optimise the hydropower reservoir usage in Norway. The temporal market succession is illustrated by figure 12: long-term hedging is followed by day-ahead spot trading. It should be noted that these day-ahead power exchanges are not the only form where *balancing responsible parties* enter into binding contracts for power delivery in real time: in contrast to mandatory power pools, power exchanges are a voluntary market platform (Boisseleau, 2004). A large share is traded bilaterally between producers and retailers, although the importance of exchanges has been increasing. This day-ahead trading is followed by *intraday* trading, offering the last possibility to enter into or adjust existing schedules. The next step, balancing in real time, is a necessary measure to correct deviations from generation and consumption schedules. The TSO activates up- or downregulation, usually based on beforehand acquired reserves, to maintain the nominal system voltage. The financial attribution of these corrective measures to single actors is handled afterwards.

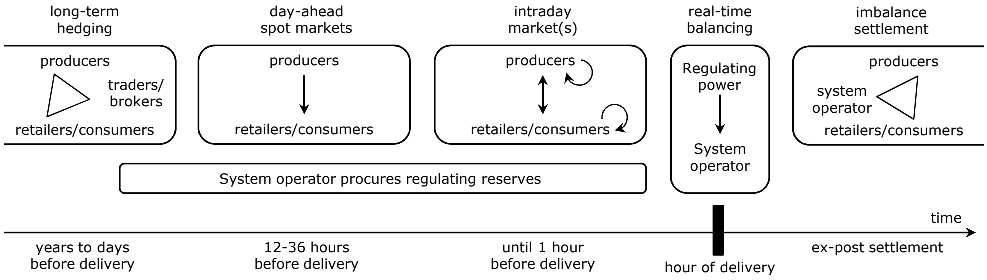

Figure 12: Submarkets of the electricity wholesale market in temporal order. Own illustration inspired by Scharff and Amelin (2011)

5.1 Day-ahead markets

All Western European countries use day-ahead markets as a tool for unit commitment and dispatch planning. The national or multinational power exchanges match demand and supply bids for all hours of the successive day. Countries or smaller market areas are mostly connected by volume- or price-coupled implicit auctions, i.e. that the power exchanges cooperatively determine flows across borders (Boisseleau, 2004). The geographical resolution is mostly national: for example France, Belgium and Germany are single market regions. In other countries such as Norway, Sweden and Denmark, several market areas apply due to bottlenecks in the transmission systems.

A different approach to price determination is *nodal pricing*, which may provide a better market framework for power systems with a large share of fluctuating RES (Neuhoff et al., 2011). A marginal generation price is computed for all major nodes of the transmission network (see Hogan, 1992, for the original concept). This is to give optimal investment and operation incentives to generation and transmission parties. The general concept is currently being applied in the US and a number of other countries, and its introduction is under discussion in Poland. In an extremely coarse geographical resolution, zonal pricing and nodal pricing could be categorised as resembling each other. Based on the wrong assumption of a frequent reshaping of market regions, Hogan (1998) characterises the Norwegian regionalisation approach as an approximation to nodal pricing. Furthermore, a major difference between the two concepts is that a system operator is in charge of the whole network under nodal pricing, including maintaining sufficient reserves in all nodes, whereas national European TSOs manage such aspects in a coordinated-decentral manner. With the increased penetration of RES generation and an associated changed congestion situation especially within national grids, Neuhoff et al. (2011) advocate the introduction of nodal pricing in Europe to achieve a more efficient system operation. This argumentation is also extended to offshore grids (Neuhoff and Boyd, 2010), and nodal pricing is considered explicitly or implicitly in Papers I - V and XI. From a power systems operational perspective, this may be the right way to give the right capacity usages under implicit allocations. However, as prices in a meshed offshore grid without demand are extremely prone to changes, it is doubtful whether this concept only is able to give the right incentives to transmission and generation owners and investors.

5.2 Intraday markets

Intraday markets are "those markets that are operating between the previously described spot markets and the physical gate closure, i.e. the time after which schedules submitted to the system operator may no longer be changed" (Weber, 2010). In single countries, e.g. Spain, they are organised as several successive auctions (Barquín et al., 2011) resembling the day-ahead market. In most countries, however, intraday trading is organised as a platform for continuous bilateral trading. On the one hand, a core issue of functioning intraday markets is market liquidity, which may be supported by the Spanish approach (Weber, 2010). On the other hand, traders may exhibit changing valuations over time, which is why continuous auctions may be preferrable (Weber and Schröder, 2011). In Germany, the TSOs in their function of balancing-responsible parties for feed-in tariff generation (see section 4.1.1) are main actors on intraday markets. This allows them the possibility to adjust their day-ahead commitments to updated wind and PV generation forecasts, giving a certain liquidity to German intraday markets. The Nordic 'Elbas' intraday market is a continuous intraday trading platform as well. Trades can be performed across all non-congested market zone borders, e.g. can an intraday trade be made between a Finnish and a Danish trader if the Swedish congestion situation allows to do so. However, both the bilateral-continuous nature of trading and the multi-border approach do not allow TSOs to incur congestion rents, as there is no optimal pricing rule for it (yet). As it improves overall market efficiency, it is nevertheless beneficial to exercise these cross-border trades, in line with the argumentation brought forward by Vandezande et al. (2010) for the exchange of international balancing and regulating power.

5.3 Regulating markets and balancing mechanisms

The use of terminology is more inhomogeneous in the field of ancillary services than for the other parts of electricity markets. In the following, *balancing* will be used as a general term encompassing both *regulating markets* and *imbalance settlement*, hence covering both the procurement and activation of regulating power as well as the financial settlement between balancing responsible parties with excess or deficit production or generation.

Both regulating markets and imbalance settlement differ remarkably between countries (see e.g. Barquín et al., 2011, for examples). In some countries, e.g. in Germany, only previously acquired *regulating reserves* are activated by the TSO for up- and down-regulation. In Denmark, the up- and down-regulation bids can be changed until shortly before real time. Moreover, qualified market participants that do not provide any guaranteed regulating reserves can also participate. This is a clear advantage for fluctuating resources as wind power. Inter alia due to the fluctuating nature, is is furthermore advantageous if no penalties are charged when it comes to imbalance settlements (Vandezande et al., 2010). Apart from some regional approaches, e.g. in the Nordic countries, balancing is mainly a national issue. This may evoke trading activities leading to inefficient market outcomes (Vandezande et al., 2009) and a cheaper system operation could be attained by sharing reserves internationally and netting imbalances (Farahmand and Doorman, 2012).

5.4 Wind energy in liberalised electricity markets

The general effects of wind integration, balancing costs and capacity values as well as a methodology for wind integration studies are addressed under an IEA wind R&D task (see e.g. Holttinen et al., 2011). More specifically, an in-depth litereature review on electricity market design and wind integration has been executed by Scharff and Amelin (2011). The most notable effect of introducing wind generation with almost no variable generation costs or under a must-run provision is the *merit-order effect*. Technologies with low short-run marginal costs replace generators with higher marginal costs, thus lowering electricity prices (see Morthorst, 2003b/Jónsson et al., 2010, Sáenz de Miera et al., 2008 and Sensfuss et al., 2008, for case studies on Denmark, Spain and Germany, respectively). This effect can partly or fully compensate for the expenses associated with the costs caused by support schemes (see section 4). However, this argumentation holds only if a constant power plant portfolio is assumed, i.e. if the increasing amount of installed wind capacity did not impact the size and generator choice of investments in other units (Wissen and Nicolosi, 2007, Sáenz de Miera et al., 2008).

The interaction of wind generators with both intraday and balancing markets has been modelled with an agent-based approach by Maupas (2008). Non-participation in intraday markets stabilises the intraday equilibrium, but may lead to very large imbalance amounts to be cleared during balancing. Considering balancing markets, an interesting solution in Belgian regulation is addressed by Vos et al. (2010). There, single offshore wind farms benefit from imbalance tariffs within a tolerance margin of 30% of the nominated generation. The preferential treatment resembles the balancing margin discussed in Paper I). The Belgian scheme can be classified as a means of indirect and somewhat intransparent support, which is why it should hardly be extended to other markets. However, it succeeds in demonstrating that there is a challenge associated to balancing offshore wind. Jansen et al. (2012) pursue a more active approach of wind generation to balancing regimes, determining their possible contribution to reserve markets.

In her seminal paper *Optimal electricity market for wind power*, Holttinen (2005) demonstrates the importance of intraday trading as a corrective measure for forecast errors. However, the interplay with other technologies participating in power markets is hard to overlook, and the existing models typically have a technical focus or take the market timing structure for granted (see Connolly et al., 2010, for an overview on energy systems models). Müsgens et al. (2012) deal with timing issues of intraday and balancing markets in a German setup which is characterised by a combined procurement of reserves and regulating power. Assuming different flexibility cost levels due to unit commitment and dispatch, Paper XV *(Power market design choices: optimal timing for wind energy)* combines wind forecast errors with different options to modify market timing – namely shortening the gate closure horizon, shortening the trading period length or shifting the existing trading period. As wind forecast certainty increases mostly during the last hours before real-time, the results reflect that only comparatively massive changes to the existing market design could reduce wind balancing costs for some scenarios. It is likely that these would be counterbalanced by extra costs from other energy system components, such as constraints of large thermal units. Hence, moving the gate closure of day-ahead spot markets, as currently investigated e.g. in the OPTIMATE project (Biegala et al., 2012), cannot be expected to have such a decisive impact as a short gate closure horizon for intraday markets (Woyte, 2008). A transition to a main market closer to real-time might be envisaged at a point in time when only few units with unit commitment constraints and slow ramping behaviour remain in the system.

5.5 Contributions of the papers to the research field

The merit-order effect described above may play to come a role in international collaborations on the erection of offshore wind power. The role of electricity market design for the operation of meshed offshore grids is addressed in a number of papers, notably I *(Interconnector capacity allocation in offshore grids with variable wind generation)*, III *(Electricity market design in offshore grids – strategic incentives under different regulatory regimes)* and XI *(Joint support and efficient offshore investment: market and transmission connection barriers and solutions)*. They all share the characteristics that they deal with potentially conflicting interests between the stakeholders involved (see section 3.5). The study presented in Paper XI analyses the effect of several offshore spot market pricing regimes on the investment framework for offshore wind investors and TSOs, namely the internal rate of return and congestion rents. Contrarily, the studies I and III address balancing issues in meshed offshore grids and strategic bidding incentives under certain regulatory setups. They show that a national onshore balancing markets cannot be directly extended to cover respective offshore wind farms situated in offshore grids as well. Instead, the congestion situation due to trading exchange flows may block this possibility, calling for a solution between the stakeholders involved. Also the results displayed in Paper III indicate that a regulatory constellation leading to strategic gaming can arise and that it may be desirable to avoid it for optimal socio-economic outcomes.

The lower market prices due to additional wind generation could come to play a role in the negotations for cost-sharing of joint support, as addressed in Paper IX *(Joint support and efficient offshore investment: market and transmission connection barriers and solutions)*. In extreme cases, wind energy under a must-run provision may even provoke negative prices at spot markets. Paper XIII *(Electricity market design in offshore grids – strategic incentives under different regulatory regimes)* deals inter alia with this issue, addressing various reasons for wind curtailment. To the author's knowledge, it is the first comprehensive study on different reasons for curtailment. Involuntary curtailment occurs mainly due to network constraints, which is a dominant reason e.g. in Northern Germany today. In a long-run equilibrium, a certain level of wind curtailment due to network constraints may be desirable to achieve an optimal combination of network and generation capacities – the ability to absorb wind generation during all hours of the year would indicate an overdimensioning of network assets from an economic point of view. However, with the currently ongoing installation of RES resources, such an equilibrium situation is far from being reached in most regions. An exception is the (radial) connection of offshore wind farms because transmission assets are built exclusively to absorb generation. Here, accepting temporary curtailment may lead to less specific generation and transmission installation cost (see e.g. JONGHE et al., 2009, for a quantitative optimisation). Voluntary curtailment is the other main category presented in the article, chiefly due to electricity market signals. Depending on how negative the price is and the support level a wind park is subject to, it can be expected to discontinue its production. Also balancing aspects can have an effect on wind curtailment: a spot market bidding behaviour accounting for asymmetrical balancing charges (ZUGNO et al., 2012) can be under the expected generation level. For certain – though unusual – balancing market constellations, wind parks may choose to curtail their generation to the reduced level they bid into the spot market.

6 Discussion

This thesis covers wind integration topics from economic and policy perspectives in general and focuses more closely on challenges of internationally meshed offshore grids. In principle, the raised points also apply for alternative technologies as ocean energy. The argumentation of a number of papers is based on existing Western European power market design, analysing its effects and how it might be gradually modified. This can be interpreted both as a drawback and a strength: on the one hand, possible benefits of more radical changes in market design are not covered. For example, this could cover market designs according to US practice with computing 5-minute schedules under a large-scale nodal pricing regime. On the other hand, radical changes to power markets may affect system security and hence, lead to high econonomic losses all over Europe. They are therefore not very likely, so the strength of the presented results lies in possible practical relevance.

A comment of a more general nature on timely planning of offshore generation and transmission infrastructure is that there are two possible approaches to a meshed offshore grid from a stakeholder/planning point of view: a) ensure a good, internationally coordinated maritime spatial planning approach for offshore wind farm siting and guaranteeing indicative capacities being built within a specified time window. This could provide reliable investment conditions for interconnections. b) ensure that specific interconnections and offshore hubs are built in the neighbourhood of designated offshore wind zones. This would have a risk-reducing effect on the planning of these neighbouring offshore wind farms. Moreover, depending on the responsibilities for establishing a grid connection and the associated risk division between stakeholders, the chances to avoid stranded investments differ. In one constellation, possibly lacking interconnections could constitute a temporary or permanent hindrance for the success of an offshore wind farm; in the opposite constellation, transmission assets risk this fate. The first approach is currently the only one being pursued, and the author is convinced that this is generally a good approach. However, he would like to emphasise that the second approach may also be promising: transmission investments are generally considerably lower than generation investments, also implying a lower investment sum potentially becoming a stranded investment. The idea of offshore wind farms following transmission infrastructure merits more analysis. It may be an interesting option showing how TSO cooperation could facilitate the erection especially of far-offshore wind parks. Currently discussed studies (e.g. Decker and Kreutzkamp, 2011, Trötscher and Korpås, 2011) assume wind generation as given input and build the offshore grid around it. The author does not challenge this approach; he challenges whether this is the right order to implement it as well because early transmission investment could facilitate offshore wind farm investment. A change can also be observed in the industry, e.g. promoted by a stakeholder consortium regarding long-term offshore grid planning (Stiftung Offshore-Windenergie et al., 2012). In every case, network and generation capacities could be coordinated in a more economic way by accepting temporary curtailment (Paper VII).

In the rapidly changing electricity sector, investment incentives giving the right signals are the main challenge because they define long-term physical facts. Market-operational measures are easier to change, but affect investment decisions considerably. Paper VI links these two topics with an operational real options approach, calculating the return for offshore wind farms based on several possible remuneration regimes. This is partly based on the unique characteristic that offshore hubs could become price nodes without internal demand under nodal pricing. Nodal pricing is an emerging topic as an alternative to existing market design and depending on how small areas count as one 'node', the approach suggested in Paper VI could, with modifications, also be extended to future onshore nodes, especially if they have little electricity demand in comparison to generation (as applies for a number of coastal regions with good wind resources). The neutral offshore pricing constellations are most likely to occur in combination with neutral, i.e. international offshore projects. These are addressed from a policy perspective in Paper V, combining support schemes with cooperation mechanisms. This combinatory policy analysis applies also to other technologies and areas and may be a careful path towards more harmonised support in Europe. However, until now, cooperation mechanisms only meet limited interest from policymakers. This can partly be explained by the fact that most EU countries plan to overfulfil their RES targets. Thus, if a cooperation mechanism is to be used, it seems most likely this will be statistical transfers covering generation from already built units. For the future, it may be good to continue this research direction with a stronger focus on institutional economics and political negotiation processes. Such an approach could lead to suggestions how joint projects and joint support schemes could be used for joint efforts to erect new generation capacity.

Besides Paper VI, also Papers I and II deal with operational aspects, especially the consequences of wind forecast errors. Papers I and II illustrate the trade-off between offshore wind park income and congestion rents and show that strategic behaviour may occur. A caveat is that they do not go as far as to propose concrete suggestions for balancing group design in meshed offshore grids, i.e. including temporarily congested interconnectors. The handling of balancing issues varies significantly between countries, which is why it may be good to base suggestions e.g. on a regulatory case study.

In the setups analysed, only the case of *one* offshore wind farm between several countries has been regarded. The strategic behaviour may be different, probably less pronounced, if several offshore wind farms connected to an offshore hub are in a competitive situation.[2] In addition, a TSO's focus on socio-economic benefits or its detailed regulation leading to this effect would have an impact on the findings. The chosen setup places an offshore wind farm between several countries. An alternative approach – although addressing a very distant future – would be to place it between two other offshore hubs in a meshed network. Assuming that connections would primarily be congested towards the country with the highest price (see Paper I), interconnectors between offshore wind parks would have idle capacity. Therefore, it is reasonable to assume that several offshore wind parks would be able to balance each other's deviations and hence benefit from spatial levelling

[2]Thanks to Ulrik Møller, Energinet.dk, for highlighting this point in a discussion.

effects. This thesis does not cover such constellations explicitly. Drawing on the main findings from the articles, it seems reasonable to argue that a joint network and offshore wind farm *operator* would be the best institutional arrangement to overcome most of these issues. For the asset *owners*, this implies that the remuneration regime should be ensured for the whole lifetime of the project. Aligning this proposition with EU unbundling rules needs to be ensured, but seems feasible with regard to the historical practice of TSOs' being in charge of selling feed-in tariff wind generation on energy markets.

Paper III requires an update towards the chosen two-country setup, providing more evidence on the comparison with similar shore-to-shore interconnector and on intraday rescheduling. This is work in progress by the authors. In line with the findings presented here, it is doubtful that an offshore hub at Kriegers Flak leads to considerably larger socio-economic benefits, especially after Sweden has discontinued its participation. It should for the future be discussed whether EU support should only be granted on the condition that a joint solution is proven as beneficial or whether a wider range for interconnectors should be eligible for support. The main result of Paper IV – that a storage should better be placed onshore than offshore – can be generalised to plans about large-scale 'Energy Islands', covering storage and generation. The level of the quantitative results presented is however prone to the assumption that HVDC interconnectors cannot provide all types of regulating reserves. The new connection between Western Denmark and Norway demonstrates that this limitation can be overcome with additional technical components.

After these reflections on the context and the implications of the topics addressed in the different papers, concluding remarks follow.

7 Conclusions

This thesis covers wind energy in electricity markets with a special focus on offshore grids. Core results are that first, generation in meshed offshore grids cannot be managed like similar onshore generation. Second, different regulatory frameworks affect investment and operation of generation and transmission in offshore grids, which is why the regulatory framework should be adjusted to reflect aspects specific for meshed offshore grids. The reason for the first point is that an interconnector with integrated generation can block the integrated wind farm from participating in an onshore balancing regime – because it is congested. Thus, the offshore wind farm is forced to interact also with balancing measures of other markets connected to the offshore grid. This may leave the operator in a better or worse position; in comparison with onshore generation, it should be accounted for. This could e.g. be implemented by adjusting the second point mentioned above, the regulatory framework. The support level could be adapted in a way that a level playing field with national onshore generation is reached. Another question is how strategic behaviour can affect the operation of an offshore grid: due to the blocking effect described above, an offshore wind park operator receiving price premium support may have an incentive for bidding a strategically advantageous amount of wind power at the day-ahead market. That way, interconnector capacity could implicitly be 'reserved'. Additional analyses show that the economics of offshore wind farms depend strongly on additional connections. On the one hand, they provide redundancy in case of line failures, but can on the other hand also increase the link to a country with lower prices. From an optimisation point of view, nodal prices lead to the right flow directions. They expose wind generators to more risk and possibly lower average income. For the reasons discussed above, it is recommended that a) one organisational entity is responsible of operating both the offshore grid and managing generation fluctuations in it. This ensures a close link between the technical operation of the HVDC grid and changing conditions. b) The grid operator can calculate flow directions with nodal prices, but wind park operators should not be exposed to these price signals to improve investment conditions. c) The combination of the two first points – no balancing responsibility for wind park operators in internationally meshed offshore grids and a low exposure to market prices – leads back to the historically most successful support scheme in many countries, the feed-in tariff.

The current developments to ensure more market participation via feed-in premiums is most beneficial under several conditions, inter alia a) if technologies can schedule their generation and b) if locations shall be chosen in a way that they constitute a good match with the residual electricity system. Regarding the first point, the scheduling ability is only very limited for wind and ocean energy. Regarding the second point, offshore sites are mainly chosen due to other excluding usages from maritime spatial planning. Hence, the benefits of choosing a price premium in comparison to a feed-in tariff are very limited and outweighed by the effects discussed in this thesis. It needs to be stressed that this evaluation is based on the assumption that the further development of offshore wind energy and a related offshore grid infrastructure is regarded as a political goal. Moreover, it takes a risk-minimising approach and is pragmatic. In theory, all undesired effects, e.g.

reallocation between stakeholders, regulatory regimes leading to over- or undersubsidisation, can be compensated by appropriate measures. An example for such a measure is adjusting the support level correspondingly. This requires however detailed knowledge by regulator (principal-agent-problem) with the risk of misjudgements. The feed-in tariff or tendering regime is therefore suggested as a pragmatic solution. In the long run, assuming a more mature offshore wind energy market, the recommendation on this point may be different if locational signals are regarded as desirable. Along with price premiums, technology-specific tradable green quotas could play a role if the locational incentive gains a greater practical relevance when accessing far-offshore sites. It should be stressed that advocating feed-in tariffs in the short to medium run also extends to support schemes with similar operational consequences. Thus, a tendering procedure with the required feed-in tariff could have similar effects. In line with already existing practice in Denmark, this could also include the feature that no remuneration is paid during periods with negative prices, therewith accounting for the main scheduling capability of wind generators. Finally, a combined daily operation of interconnectors and generation on electricity markets is not against EU unbundling rules, as historical evidence on feed-in tariffs shows. A closer combined operation or, in an extreme case even combined ownership, may face difficulties under the existing legislative framework in the EU.

In electricity systems with an increasing penetration of fluctuating renewable resources, generation curtailment will play an important role in the future both at onshore and offshore locations. An intuitive example is the grid connection of an offshore wind farm: today's practice in several countries is to dimension the interconnector at the nameplate capacity of the wind farm, although the full capacity will hardly ever be utilised. From an economic viewpoint, this is inefficient and leads to two conclusions: first, accepting curtailment can become important to achieve a more cost-efficient integration of renewables. Second, where transmission assets are overdimensioned under the assumption of curtailment acceptance, more generation could be added without paying significant additional grid connection costs. A regulatory framework setting such incentives is, as for the market-operational offshore grid examples addressed above, a key challenge for the future.

In summary, this thesis provides new insights on wind energy in offshore grids as well as on related issues. Thanks to their publication in journals and dissemination at scientific conferences, all results are already part of the scientific dialogue.

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– Appendix I –

Interconnector capacity allocation in offshore grids with variable wind generation

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BROADER PERSPECTIVES

Interconnector capacity allocation in offshore grids with variable wind generation

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ABSTRACT

Different capacity allocation regimes have a strong impact on the economics of offshore wind farms and on interconnectors in offshore grids. Integrating offshore generation in offshore grids is currently a subject of discussion for different regions, e.g. the North Sea. A novel question is how the interconnector capacity should be allocated for wind generation and for international power trading. The main difficulty arises from the stochastic nature of wind generation: in a case with radial connections to the national coast, the wind park owner has the possibility of aggregating the offshore wind park with onshore installations to reduce balancing demand. This is not necessarily the case if the interconnector capacity is sold through implicit or explicit auctions. Different design options are discussed and quantified for a number of examples based on Danish, Dutch, German and Norwegian power markets. It is concluded that treating offshore generation as a single price zone within the interconnector reduces the wind operator's ability to pool it with other generation. Furthermore, a single offshore price zone between two markets will always receive the lower spot market price of the neighbouring zones, although its generation flows only to the high-price market. Granting the high-price market income for wind generation as the opposite design option reduces congestion rents. Otherwise, compensation measures through support schemes or different balancing responsibilities may be discussed. Copyright © 2012 John Wiley & Sons, Ltd.

KEYWORDS
capacity allocation; interconnectors; offshore grids; offshore wind; power markets; wind energy

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1. INTRODUCTION

The integration of large amounts of renewable energy is a subject of ongoing discussion. Different proposals have been met with a considerable degree of media attention,[1,2] with that of Airtricity[2] focusing on the possibility of offshore grids. Their purpose is to combine the uptake of offshore wind generation with the economic benefits of international transmission connections for power trading. This paper discusses how the interconnector capacity can be allocated between these opposing purposes. It extends therefore the work carried out by Roggenkamp *et al.*[3] and under the OffshoreGrid project (www.offshoregrid.eu). Obviously, this is a question of power market design. Nodal pricing is suggested as the most efficient option for offshore grids in a paper that has been taken into account by the European Coordinator on the connection of offshore wind power.[4] It is argued that this is the most efficient option because it reflects interconnector congestion but does not address issues like the effect of nodal pricing on offshore wind farm investment certainty under national policy schemes and regulation. Internationally integrated balancing markets would provide a least-cost solution.

As this perspective is quite different from today's status dominated by national power markets, this paper analyses possible transitional regimes such as offshore wind generation belonging to a national market while being part of an offshore grid. It addresses different interconnection capacity allocation regimes and highlights two design options of nodal pricing. It is illustrated that the normal situation for offshore wind generation is that the operator can use the interconnector capacity to the mainland without paying congestion rents. In comparison, this paper assesses the question under the exemplary case of an offshore generation site within a single interconnection between two neighbouring markets.

This issue is up-to-date and needs to be clarified for the discussed Kriegers Flak offshore node[5,6] and North Sea offshore grid initiatives. Under implicit auctions, which are predominant in Northern Europe, offshore generation could be represented as being a single price zone without any consumption. Under explicit auctions, it would be discriminatory to make the offshore generation owner pay for obtaining transmission capacity to a market. A certain capacity might thus be allocated for free to the offshore generation owner. Setting this at the nominal capacity of the installation leads obviously to escaped benefits from international trading for the transmission system operator (TSO). Allocating the hourly expected generation according to the offshore installation owner gives him an incentive for gaming, i.e. permanently nominating too large values. A possible compensation for restricted national market integration is the concept of the balancing margin. It constitutes a capacity reservation on the cable to partially incorporate an offshore wind farm with onshore generation in the same balancing group. A number of other different economic effects need to be taken into account, reaching from different possible spot market affiliations to insurance values for being connected to several markets.

The paper is structured as follows: first, power market and interconnector capacity allocation issues are addressed. Second, capacity allocation scenarios under different price zone designs are presented. The following quantitative overview is complemented by a quantitative case study to highlight the magnitude of the discussed topics. Finally, the discussion and conclusion complete the paper.

2. POWER MARKET DESIGN

2.1. Power markets

All relevant European power markets' product range, as on Nord Pool, EEX and Powernext, can be subdivided according to their time distance to actual power delivery. Nord Pool is used as the central example in the following.

In a system without external trade, supply and demand curves are matched on *day-ahead markets* to determine the market price per period. All market actors bid the amounts they are willing to sell or buy at certain price levels (see the thesis of Boisseleau[7] for a more detailed description). By participating in the market, they have to be recognized as being balancing-responsible. After aggregating all actors' curves to a market demand and supply curve, a market equilibrium will determine the market price and the total trading volume.* All accepted bids, disregarding their level, are thereafter cleared at this marginal price. In the case where an actor deviates from the plan established by the day-ahead market, he can correct it at the intraday market or might have to pay balancing fees.

Intraday markets work as a platform where parties interested in selling or buying can post their bids, which are matched by the exchange. Continuous trading is possible from the closure of the day-ahead market to 1 h before physical delivery. Liquidity in intraday markets is commonly lower than in day-ahead markets.

Balancing markets (also called regulating markets in some countries) are subdivided into primary, secondary and tertiary (or minute) reserves. The detailed market designs differ between countries, but it can generally be said that primary and secondary reserves are provided to correct deviations up to 15 min to stabilize the system frequency, which is why the procurer receives capacity-based payments. Besides capacity procurement remuneration, tertiary reserves are generally based on energy provision (€/MW h) and in the focus of the following discussion.

The basic condition for balancing is that one or more balancing-responsible parties (BRP) deviate from the announced plans of their balancing groups. The applied mechanisms for the calculation of the resulting financial impact are different in the former UCTE and Nordel regions. As examples, the German and Danish methods are discussed. The net sum of BRPs' imbalances has to be supplied by the bidders in the regulating market, where the TSO acts as a single buyer.

In Germany, the underlying principle is that every megawatt hour of deviation has the same monetary value. As the procurement auction is a pay-as-bid auction, the bid units are activated in the order of their bids.[8] The average balancing price is the weighted average of the activated regulating power. The clearing among the BRP with deviations from their schedule is symmetrical, so both positive and negative deviations are cleared at the average balancing price.

Denmark is part of the common Nordic regulating market at the Nord Pool power exchange. The underlying principle of remuneration is whether a balancing-responsible party contributed to system stability. Whenever it does so, the spot market price is taken for settlement. However, if its deviation from schedule increased the system deviation, it has to pay the regulating power price. This is based on a unit-price auction for both up- and down-regulation.†

*The case that supply and demand curves do not intersect can theoretically occur but is highly unusual in the relatively liquid day-ahead markets.

†Until 28 May 2008, it was a unit-price auction for Western Denmark only. Until today, pay-as-bid might still be applied in special circumstances to relieve internal congestion.

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2.2. Interconnector capacity allocation designs

This section deals with the question how the capacity of an interconnector can be allocated commercially. The discussion refers only to interconnectors between electricity price zones and not to transmission tariffs within such a zone. Two competing approaches are currently used in Europe: explicit and implicit auctions.*

Explicit auctions are the traditional method in the former UCTE interconnection zone and are still used for a number of interconnectors in Central and Western Europe. Technical safety margins are deducted from the physical capacity of the connection, and the remainder of the capacity is auctioned in both directions. A rather coarse overall auction design can lead to the effect that planned flows in both directions net each other, leading to a suboptimal socioeconomic outcome. For day-ahead auctions, the relative timing to power spot markets is decisive: interconnector auctions are finalized before the gate-closure time of day-ahead spot markets. The highest bids receive the available capacity at the price of the lowest accepted bid. If the price equals 0, this is an indicator that the line is not congested. Unused day-ahead capacity can be sold further in an intraday auction. The income from all auctions is given to the interconnector owner, typically the two national TSOs of the respective countries. Real market outcomes show that the explained law of one price hardly ever holds, which is mainly because of uncertainty and related gaming. For this reason, a number of West European power markets get connected via implicit auctions. The concept of explicit auctions helps illustrating the following argumentation as a vehicle because actor's roles are clearer.

Implicit auctions are no capacity auctions in the classical auction style, but an integral piece of a power market with several price zones. After having obtained all day-ahead bids, Nord Pool calculates a common system price for all price zones. In a next step, the interconnector capacities are taken into account. If the system price calculation demands power flows on interconnectors that exceed their capacities, the flow is reduced to their capacity. This implies that a more expensive unit will have to be switched on in the importing country. Thus, the interconnector usage is auctioned implicitly with the power exchange as a mediator. The mechanism of implicit auctions avoids the inefficiencies of explicit auctions. It also results in the necessity to use the power exchange for international trading because a market actor cannot obtain interconnector capacity directly.

2.3. Offshore wind generation in power markets

The installation of offshore wind parks is not economically viable in liberalized electricity markets. The design of different support schemes varies between the single EU countries, but priority feed-in is practised in several of them. This means that renewable energy is produced, disregarding whether this is currently useful for the overall energy system. The extremely low marginal costs of wind power production indicate that the outcome in a liberalized market with positive market prices only would be similar. In Denmark, most renewable energy technologies receive a premium on top of the market price. Introducing negative prices at the Nord Pool spot market since October 2009 onwards changed the picture: power producers do not generate if costs exceed the premium per generated megawatt hour.

Another central topic is the connection of offshore units to the grid. A common characteristic of most countries is that network infrastructure until the offshore site is owned by the network operator—which gives them the option to use their asset as well as possible, also for other purposes as commercial electricity transmission.

3. CAPACITY ALLOCATION SCENARIOS IN DIFFERENT PRICE ZONE CASES

Different price zone designs can lead to different scenarios for the capacity allocation. This section addresses the possible combinations with a simple setup: the offshore generation is located between the markets (i.e. price zones) A and B. A concept used in the following cases is the balancing margin. Its purpose is to give the offshore wind farm operator the right to combine generation with the onshore generation in region A before addressing intraday and balancing markets; it does not correspond to the total security margin but is a surplus for correcting the offshore wind farm's stochasticity within a balancing group. It is defined as a percentage of hourly planned generation and, thus, is proportionally fluctuating.

3.1. Case 1

This is the standard setup: the offshore wind farm has a radial connection to the country it belongs to, as illustrated in Figure 1. Obviously, the cable can only be used for transmission of power generated in the offshore park. If the line has been dimensioned as to cover the full generation capacity of the offshore park, it will never be congested. However, failures of single engines and spatial stochasticity of wind mean that this full capacity will hardly ever be achieved, which is why the connection line is usually dimensioned smaller to achieve an overall optimal investment. For the UK, it is estimated

*For alternative approaches of capacity allocation, e.g. see Duthaler and Finger.[9]

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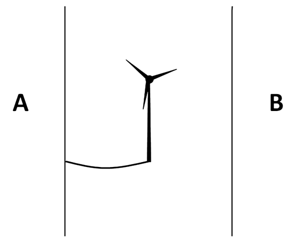

Figure 1. Case 1—national radial connection.

that the wind park capacity should be at 112% of the cable capacity in order to achieve an optimal constellation.[10] In Germany, this effect could be achieved by the regulatory design that the network owners have to compensate renewable energy generators under the feed-in tariff for lost generation due to capacity constraints, if not all generation had to be absorbed.

3.2. Case 2

In this setup, the offshore generation site is in the middle of a transmission line between the price zones A and B. For reasons of simplicity, it is assumed that the transmission capacity is the same as in case 1 over the whole distance. Furthermore, additional line losses due to a more complicated technical layout are neglected. The key characteristic of this setup is that the offshore generation is incorporated in price zone A, as illustrated in Figure 2. This can be helpful to fit with other questions of market regulation, e.g. if a promotion scheme is only granted for national generation. The effect of this regulatory design is that a bottleneck is in some cases moved towards country B to incorporate offshore generation in country A. Moving bottlenecks to national borders is allegedly against the principles of European free trade[11] because it discriminates between different network users and 'pursue[s] a purely national policy aim'.[12] The combination of offshore wind connection and electricity trading is a novel situation. In the simple case illustrated here, electricity customers would be discriminated against only to a minor degree if resulting power flows are under an individual offshore price zone (following case 3). Nevertheless, the offshore wind farm interacts only with its home country's markets where it tends to lower spot market prices. It is beyond the scope of this paper to assess the legal implications of this case under EU regulation.

Under explicit auctions, the remaining capacity—after incorporating offshore generation—can be sold. This leads to the following time steps:

1. Offshore generation is forecasted and announced
2. Explicit capacity auction (day-ahead)
3. Bidding at the zonal spot markets

The available capacity for step 2 is the overall transmission capacity (CAP) towards B and its residual with planned offshore generation (G) towards A. Furthermore, a balancing margin (M) is introduced to represent the stochasticity of the offshore generation.

In summary, $(CAP - G - M)$ can be offered from zone B towards zone A, whereas CAP can be offered from A towards B. The reason is that if A imports from B, the residual available capacity is restricted by offshore wind generation. If A exports towards B, the full capacity can be sold because offshore wind generation is a part of market A. Up to the limit M, the offshore generation operator can internally balance his generation with onshore generation in A. For deviations exceeding M, zone-internal countertrading will have to take place. It is therefore hard to determine the optimal size of

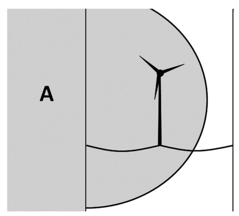

Figure 2. Case 2—incorporation into one country's zone.

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M. With progressing time and lower forecasting insecurity, shares of M might also be sold on intraday capacity auctions. Irrespective of the detailed design of the balancing margin M, a basic drawback remains: all bidders on explicit auctions achieved a symmetrical gaming structure. They bid a price to obtain a real option for one-way power transmission. If they do not use it, it expires (under a use-it-or-lose-it regime). The situation is different for the offshore generation operator who can transmit his generation for free to his mainland A. Granting this transmission right for the offshore generation is a question of non-discrimination in comparison with case 1 (above), but results in the effect that there is an incentive to announce unrealistically high-generation plans to procure the right. From a socioeconomic point of view, this leads to too little capacity being sold for trading. Another major drawback is that the offshore generation operator could announce his usage/non-usage of interconnector capacity strategically because he has an informational advantage: before other market actors, he knows whether additional capacity will be available soon on the market, i.e. whether intraday prices in the two zones could converge. The offshore operator benefits in still another way from this solution: in case of a line failure to zone A, he can still sell his production in zone B—although market rules would have to be adapted. Thus, it constitutes an insurance value for the offshore operator.

Under implicit auctions, the capacity to be auctioned is as variable as under explicit auctions because the day-ahead expected generation is an input for the trading capacity determination. Consequently, the same argumentation applies analogously; only steps 2 and 3 (capacity auctions and zonal price calculation) are simultaneous because of the basic design of implicit auctions. An interesting aspect is the design of the suggested balancing margin M. In order to ensure non-discrimination in comparison with case 1, the existence of M towards A is a proper measure. However, the capacity not absorbed by the wind turbine stochasticity can be given to the intraday- and balancing market. On Nord Pool, there is one common intraday market price if lines are not congested; if the day-ahead market led to congested lines, intraday and balancing prices are determined separately on both sides of the transmission bottleneck. If now, with progressing time, it is realized that M is not needed for wind power deviations and is therefore transferred to the implicit auction mechanism, the capacity can be opened for intraday and balancing markets. This leads to the constellation that initially different prices could converge after additional capacity became available for trading.

3.3. Case 3

This case describes a situation with a separate offshore price zone. It is denominated as the extra price zone C between the mainland price zones A and B (see Figure 3). Its main difference from case 2 is that the offshore generation does not belong to a price zone but has symmetrical relations to both neighbouring zones. A hitherto unseen power market would come to life in C: generation only, without any demand. Systematically, this leads to the known situation where supply and demand curves do not intersect. A market design with a single TSO in C responsible for system stability is unthinkable with a small number of fluctuating generation sites. Instead, it is assumed that it is managed externally by one of the neighbouring TSOs. This principle should also be applied with regard to network charges: price zone C should be incorporated in the neighbouring zones' network charges regimes. In the following, it is discussed what the design with a single offshore price zone implies under explicit or implicit auctions.

Under explicit auctions, the trivial case would be that the offshore generation operator has to buy transmission capacity to the neighbouring zones. Because of the market mechanism itself, wind stochasticity and the non-discrimination issue discussed for case 2, this would lead to a grossly inefficient outcome. The intermediate zone C does not have any demand, which makes matching demand and supply offers impossible. The price can only be determined by price differentials to neighbouring zones, i.e. that the price corresponds to the price in a neighbouring zone plus the congestion rent towards this zone. Such an approach can be considered pure gaming. In analogy to case 2, the offshore generation operator could be endowed with the right to reserve transmission capacity day-ahead for free. This right could be granted either towards price zone A only or towards both A and B—the right to choose this would constitute an advantage for the offshore generation

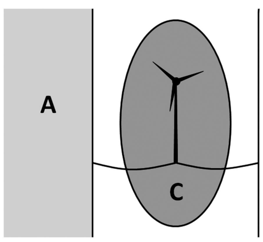

Figure 3. Case 3—independent price zone.

operator, as he chooses it towards the zone with the probably higher price. For this amount, the TSO cannot collect any congestion rents afterwards. The argumentation with regard to intraday markets and balancing rules are analogous to the elaborations for case 2.

Implicit auctions with a separate offshore price zone are the more relevant situation. Firstly, implicit auctions are advancing as a congestion management instrument. Secondly, the incorporation of offshore generation in a neutral, single price zone between demand centres matches with ongoing discussions about cross-border offshore wind parks. It represents the nodal pricing suggestion brought forward by Neuhoff and Boyd.[4] If the transmission line from C to A and B has a smaller capacity than there is generation capacity in C, this price zone could experience lower day-ahead prices than both neighbouring zones. However, the line capacity has been defined above in a way that it can usually absorb at least the whole generation. In all market situations, the price in C will be the minimum of the prices in A and B because the bottleneck (i.e. the price border) is between offshore generation and the high-price zone. This is caused by the fact that merely the intended generation G is announced, but none of the interconnectors is explicitly reserved.

Figure 4 illustrates this effect exemplarily: the price p is lower in zone A than in zone B. The capacity of the interconnector is at 500 MW, which B imports and which is partially generated in C and partially exported from A. The physical bottleneck arises between the offshore generation zone C and the high-price zone B: for this reason, offshore generation will always incur the lower price of the two neighbouring zones. Next, a situation with three or more price zones connected to the offshore hub is regarded. Then, the price at the offshore hub is an intermediate between the lowest and highest neighbouring price. It is identical to the price in the neighbouring zone to which the interconnector is uncongested.

An interesting situation can evolve when the interconnector's capacity is blocked one-way, e.g. towards zone A. This implies that a full participation in intraday and balancing markets is only possible in country B. The setting turns more complicated if a balancing margin M is introduced in analogy to case 2. Note, however, that the basic argumentation for a balancing margin was that the offshore generation operator should be able to combine the offshore site with onshore generation for balancing purposes (to achieve a level-of-playing field with case 1). This calls for granting such a balancing margin to only one of the neighbouring zones: either where the power is delivered to (i.e. the high-price region) or to the low-price zone (where there is no congestion, i.e. no economic loss of congestion rent). The latter option is chosen here because it does not reduce the capacity available for day-ahead trading. It merely limits the offshore operator's ability to provide offshore generation in excess of the schedule (i.e. positive balancing in the high-price zone). The remaining cases (negative balancing with the high-price zone and both positive and negative corrections with the low-price zones) are not touched by this setting. Finally, the positioning of offshore generation in the middle of an international transmission line with implicit auctions reduces the investor's risk. This is because the spot market price volatility for generation between two price zones linked by implicit auctions is lower than a connection to merely one zone.

3.4. Capacity allocation possibilities: results

Table I gives an overview of the previously discussed constellations. It considers prices and capacities when operational.

Under case 1, the offshore operator can use the full capacity for trading at the day-ahead spot prices of zone A, $p(A)$. This applies for intraday and balancing participation as well. The TSO does not receive any congestion rents.

Under case 2 and explicit auctions, the offshore operator can sell his generation and join balancing at $p(A)$. Furthermore, not relying on one line gives an insurance value and possibly market power on capacity and power auctions (because of the option to delay non-usage of the balancing margin M strategically). The TSOs collect the auction revenue of the capacity CAP after considering planned offshore generation G and the balancing margin M, both reserved for the offshore operator. Unused shares of G and M (marked as Δ) can later be sold for interzonal intraday and balancing.

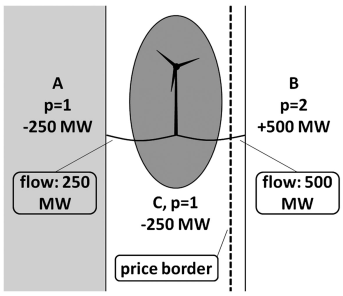

Figure 4. Location of the price border under implicit auctions.

Table I. Overview of allocation scenarios.

	Auction	Offshore operator	TSOs
Case 1	–	Spot: $p = p(A)$	–
		Intraday/bal.: $p = p(A)$	
Case 2	Explicit	Spot: $p = p(A)$, G	$CAP(-G-M)$
		Intraday/bal.: $p = p(A)$, ΔM	ΔG, ΔM
		Insurance value, strat. market	
		Power on auction markets	
	Implicit	Spot: $p = p(A)$, G	$CAP(-G-M)$
		Intraday/bal.: $p = p(A)$, ΔM	ΔG, ΔM
		Insurance value, strat. market	
		Power on power exchange	
Case 3	Explicit	Spot: $p = \max(p(A), p(B))$, G	$CAP - G$
		Intraday/bal.: $p(A)$ or $p(B)$	ΔG
		Insurance value, strat. market	
		Power on auction markets	
	Implicit	Spot: $p = \min(p(A), p(B))$, G	CAP
		Intraday/bal.: $p(A)$ or $p(B)$	ΔG
		Insurance value, strat. market	
		Power on power exchange	

The most important aspect of case 3 is that the remuneration of the offshore operator depends on the auction design: Under explicit auctions, he will reserve the transmission capacity G to the neighbouring zone where the higher price can be expected. Contrarily, implicit auctions will always locate the price border between offshore generation and the high-price zone. Offshore generation will therefore be situated in the low-price zone. As there is no specific link to one of the neighbouring price zones in this scenario, the balancing margin M is not necessary. This limits the offshore operator only when he could sell positive balancing to the high-price zone. Neglecting this special case, the offshore operator can engage in intraday and balancing trading in both A and B. The TSOs can obtain a congestion rent for the interconnector capacity minus the reserved generation. Under case 3 with implicit auctions, the TSOs can collect the full congestion rent of the capacity (at the disadvantage of the offshore operator). The offshore operator can choose the intraday and balancing markets if access is not limited by interconnector congestion.

4. CASE STUDY

4.1. Data

The discussed topic is novel, and therefore, there is no location with all relevant data available to illustrate a real-world case (as carried out for onshore wind, e.g. in Gibescu *et al.*[13]). The author decided to quantify the magnitude of the previously discussed concepts with a fictitious case based on available data: as a representation for the offshore wind farm, data for the Danish location Horns Rev I have been assessed. It was erected in 2002 and has a capacity of 160 MW. The data comprise the wind park's aggregated hourly output for the years 2007 and 2008 as well as several forecasts of up to 48 h ahead. This is combined with power market prices from a number of Northwest European markets, namely West and East Denmark, Germany, the Netherlands and Norway. In all of the following examples, the day-ahead forecast (i.e. 13–37 h ahead) is compared with actual generation. The amount of non-reliable or missing data points is below 1%.

4.2. Monetary value of offshore imbalances

Figure 5 shows the relative frequency of deviations from the day-ahead forecast in monetary terms—in other words, the value per megawatt if all deviations were corrected at the balancing market under a price-taking approach. The deviations (MW h^{-1}) are multiplied with the respective monetary values (EUR MW h^{-1}) according to the balancing rules applying for West Denmark. As explained earlier, this can be either spot or regulating market prices. The data are sorted in classes with a class width of 5 EUR h^{-1} except for the two outer classes; classes are denominated by their average value. This figure describes the benchmark case: if all deviations from this site need to be corrected by balancing, the financial consequences as shown in Figure 5 arise for case 1. This amounts to 34% of the day-ahead sold spot market value over the regarded 2 years.

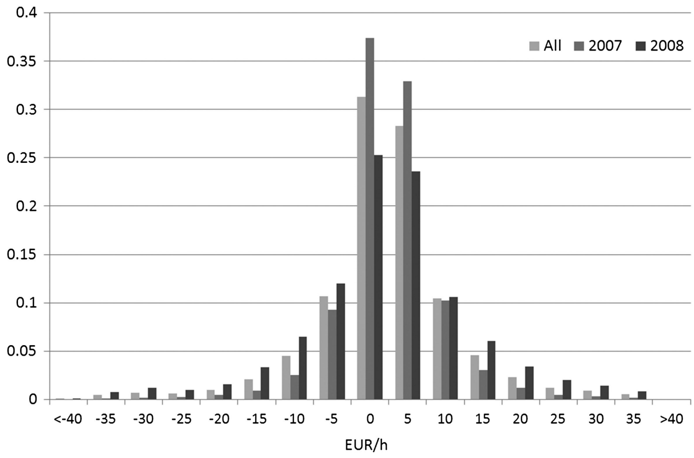

Figure 5. Relative frequency of balancing market values of Horns Rev I deviations per installed megawatt.

4.3. Capacity allocation

Figure 6 shows the average annual income per megawatt for the TSO and the offshore operator (2007/2008) for a number of locations. The national market of the wind farm is denominated as A and the other country as B. A wind farm with Horns Rev I production patterns is thus placed in a number of discussed or existing interconnectors (e.g. CobraCable between the Netherlands and Denmark-West, Kriegers Flak, NorNed or NorGer). The numbers cover only spot market values and are based on the absence of a balancing margin. Including balancing aspects for a full comparison of all three

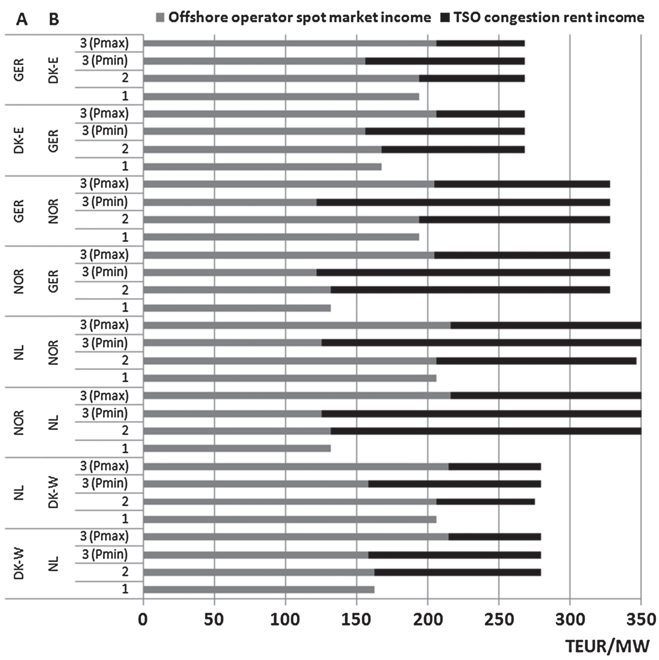

Figure 6. Average spot market and congestion rent revenues for several national market combinations.

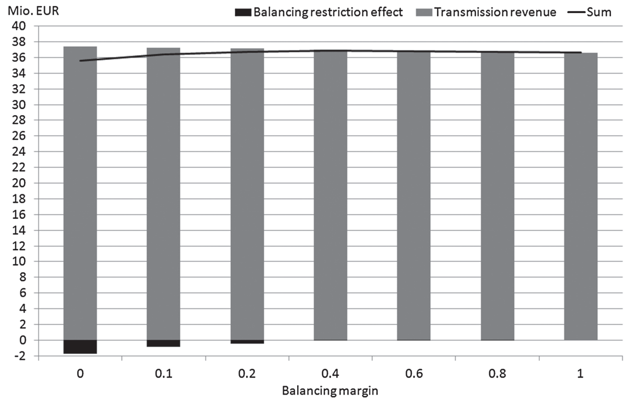

Figure 7. Monetary consequences of a balancing margin for the TSO.

cases requires incorporating both neighbouring balancing mechanisms and market prices, which has not been carried out for case 3 because of nationally different balancing principles.

For case 1, the TSO has, trivially, no income from the line because there is no interzonal power trade. The offshore operator incurs the spot market price from zone A (between 132 and 195 TEUR MW^{-1} $year^{-1}$). For case 2, the latter value is the same, and the TSO has additional income from the implicit auctions. This income might be lower if a balancing margin is introduced or the TSO is responsible for balancing offshore fluctuations. The two different arrangements of case 3 illustrate that the offshore operator will have less income if he receives only the lower of the two neighbouring spot market prices; the TSO's income increases by the same amount. The picture is reversed if the market design was such that the offshore operator always obtains the higher price of the two neighbouring price zones. For some locations as a possible connection between Denmark-West and the Netherlands, the congestion rent income is almost cut in half. In conclusion, this zero-sum game moves income between offshore wind farm operators and the TSO. Valuing offshore generation at the higher of the neighbouring prices reduces the need for economic support while reducing congestion rents. When taking the decision to build an offshore grid, such a market design has a negative effect on the TSO's private-economic analysis of congestion rents and would systematically undervalue possible benefits.

For case 2, a conflict about capacity allocation arises: if a cable of 160 MW was installed, e.g. between West Denmark and the Netherlands, the revenue for the 2 years would have been at 38.8 Mill. Euro (assuming a price-taking approach). Figure 7 shows the aggregated 160 MW interconnector income for 2007 and 2008 under the assumption that the day-ahead expected generation and a balancing margin constrain electricity trading. Because the offshore site is incorporated in A, offshore generation reduces the available transfer capacity only when power is imported into A (Denmark-West). Consequently, the transmission revenue is reduced from 38.8 to 37.4 Mill. Euro as a maximum value. The second issue indicated in Figure 7 addresses the financial impact of the balancing restriction on the offshore operator: a problem arises whenever country A imports electricity, the line is congested and the offshore wind farm generates more than what is planned. Then, it cannot sell this on A's regulating market because of the congestion. Note that there is a maximum at 0.4: until this point, the TSO's additional income from trading is less than the offshore operator's escaped profits because of an insufficient balancing margin. In principle, these considerations also hold if intraday markets are taken into account, although an optimal solution strongly depends on price differentials between the different markets.

5. DISCUSSION

The presented considerations and results show that market design has a strong impact on the allocative outcome between an offshore generation owner and the neighbouring TSOs. The approach taken here comes from the idea that an offshore generation operator should be indifferent whether his site is part of an international offshore grid or not. This is why transmission capacity is granted for free to him for trading at the day-ahead spot market and also for balancing purposes, if the offshore site has a national affiliation. Under all circumstances, the author suggests that the offshore operator should have an incentive to announce real expectations instead of gaming, e.g. by putting penalties on a non-symmetric distribution of announced values. This could be implemented by a penalty if the distribution of overestimations and underestimations is not symmetrical. The author demonstrates further that a number of conflicting economic effects, such as an insurance value for a connection to a different power market, need to be taken into account. For the case of a separate offshore price zone under a nodal pricing regime, he shows that choosing the physical bottleneck as a border between price zones is disadvantageous for the offshore operator. It may therefore be considered to remunerate offshore generation always at the price of the higher neighbouring price zone. This would be analogous to an outcome under explicit auctions. A general drawback of a nodal pricing regime is that several offshore wind farms connected to different nodes would receive different remunerations for their electricity generation, even if they belong to the same country. This might be reflected by adjustments in support mechanisms, e.g. a guaranteed average income relative to national onshore spot market prices.

A balancing margin, which reserves interconnector capacity for integrating offshore wind generation within an onshore balancing group, could be a pragmatic solution to the offshore balancing issue. However, overall benefits from an offshore grid are larger if offshore generation interacts with all neighbouring balancing mechanisms.

A limitation of the presented work is that it focuses at the operational perspective only, as opposed to investment decision making. Furthermore, it assumes responsibilities as given today. Contrarily, in an offshore network, it might be possible that the TSOs are responsible for forecasting offshore generation and balancing it. The duty to balance the generation would thus be withdrawn from the offshore owner, which can be regarded as an advantage. This can be compensated with other measures, e.g. paying only the lower of the neighbouring day-ahead prices as discussed above or adjusting the support scheme level. The author stresses that the introduced balancing margin is a theoretically helpful concept but depends on forecast precision and electricity market prices. A perfect balancing margin can only be determined *ex post*, which is a hindrance to its application. The presented work does not include monetary valuations for all relevant aspects, such as for the insurance value of having an additional line to an offshore site. The concept of the balancing margin might first show to have practical relevance when offshore wind generators are incorporated into a transmission line at Kriegers Flak in the Baltic Sea.

6. CONCLUSIONS

This paper shows that different capacity allocation options have strong consequences on both offshore wind operators and TSOs. The choice whether to incorporate an offshore site in an onshore price zone or to have it as a stand-alone zone under nodal pricing is a crucial question. Both cases do not leave the offshore operator indifferent in comparison with a national radial connection: under nodal pricing, spot market income and balancing costs are different. Under national incorporation, the difference results only from limited access to the onshore balancing group and balancing mechanisms. These considerations are based on the assumption that the capacity of the offshore wind farm is identical with the interconnector capacity to both shores. Increasing the transmission capacity to one side improves the price convergence between the offshore wind farm and the respective onshore market. In other words, the incorporation of the offshore node in a country's onshore market can also be approximated under nodal pricing by interconnector dimensioning.

In establishing a single offshore price zone under a nodal pricing regime, it is to a certain extent a normative question whether the offshore zone should obtain the higher or lower neighbouring price. The high-price option could reduce the required amount of support but also income from congestion rents. This might justify the introduction of additional compensation measures such as a balancing margin. Assuming a fixed support level, interconnector capacity allocation is a redistributional question between the TSO and the offshore operators and needs to be seen in the context of other questions, e.g. the insurance value of having an additional connection.

A full quantification of these effects and a closer analysis of the illustrated effects under integrated balancing markets are interesting cases for further research. In addition, having several offshore wind farms at several locations in one interconnector seems worthy of additional analyses. The impact of connecting offshore generation to multiple countries, instead of two only, would also have systematic consequences on the discussed effects.

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– Appendix II –

Electricity market design in offshore grids – strategic incentives under different regulatory regimes

Sascha T. Schröder

based on an earlier paper presented at the 10th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, Aarhus

Electricity market design in offshore grids – strategic incentives under different regulatory regimes

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Abstract-- This study addresses different market design options for meshed offshore grids. It demonstrates that a mere transfer of current market design may lead to undesired incentives. An offshore wind farm can either be affiliated to an onshore zone or be an independent zone as e.g. under nodal pricing. Under feed-in tariffs and price premiums, the offshore wind farm's and transmission system operator's incentives are contrasted. It is shown that in a number of cases, bidding a different amount than expected wind generation into day-ahead markets can be advantageous for a single actor. In practice, the conceptual considerations depend strongly on price differentials between markets neighbouring the offshore grid. The offshore wind farm may have an incentive to withhold generation for spot markets under nodal pricing because this opens access to higher-price markets. It is concluded that specific offshore grid market designs should be discussed to ensure that socio-economically optimal outcomes are achieved under all possible constellations. Feed-in tariffs leave the wind marketing responsibility to the transmission system operator, which can co-optimise wind and congestion management. If the support level is constant, this integrated approach is superior to price premiums where there are strategic incentives for the offshore wind farm.

***Index Terms*-- Electricity markets, offshore grids, wind energy**

I. Introduction

THE possibility of large-scale overlay grids at a higher voltage level, also referred to as Supergrids, has received increasing attention in the last years. They could facilitate the large-scale integration of offshore wind erections that are planned in a number of European countries (Green and Vasilakos, 2011). The first seminal work on the supergrid topic was by Czisch (2005), who demonstrated how the European electricity system could be supplied with renewable energy at a reasonable price if the solar potential in Northern Africa is linked with a number of technologies in Europe, mainly wind energy for Northwestern Europe. This insight has led to a number of industry initiatives, e.g. by Airtricity (2006) and EWEA (2009). The latter one is a detailed road map for the erection of offshore connections in the North and the Baltic Sea, both establishing direct interconnectors from shore to shore and for a meshed grid including offshore wind generation. This report has during the last years been complemented by different scientific reports under the OffshoreGrid project (De Decker and Kreutzkamp, 2011). It is complemented by the studies of Bettzüge et al. (2010) and Egerer and Kunz (2011). A technical optimisation on the topology of such a meshed offshore grid has been developed by Trötscher and Korpås (2011). Looking at single projects, Roggenkamp et al. (2010) analyse legal and economic aspects of establishing offshore wind farms in one country and possibly connecting it to another one. First valuable experience on establishing meshed structures is gained in the Kriegers Flak project in the Baltic Sea, where both Denmark and Germany plan to erect offshore wind farms in close proximity

(Energinet.dk et al., 2009). Connecting these offshore wind farms to benefit from electricity trade is envisaged and supported by the EU Commission because it increases the integration of European electricity markets. Neuhoff and Boyd (2010) come forward with the proposition that nodal pricing is the regime giving the right incentives to all concerned market participants. An earlier paper looking at the economics of the offshore wind farm in an offshore grid, in comparison to the standard national connection, is by Schröder (2011). There, it is argued that an offshore wind farm operator's income depends on electricity sales on the available markets. He can adjust generation fluctuations either internally, i.e. by corrections of onshore generation in the same balancing group, or externally, i.e. by being exposed to balancing regimes. An offshore-grid-integrated wind farm's ability to participate in balancing and regulating regimes of a specific country is limited through congestion caused by international power trading. This affects the offshore wind farm's profitability, while countermeasures might limit the benefits from offshore grids.

While Klessmann et al. (2008) analyse the advantages of feed-in tariffs and price premiums in general, the existing research gap consists of a more general approach addressing the specific incentives than can arise under different regulatory constallations in offshore grids. This article attempts to fill this gap. It extends the work presented in Schröder (2011) and provides a more comprehensive conceptual and analytical framework with regard to support schemes and national affiliations. More precisely, this means that the cases presented there are generalised and strategic incentives for the involved market actors are presented. The article is structured as follows: first, the model and the general setup are introduced. We assume that actors, namely the offshore wind farm and the transmission system operator, interact in a two-step game. Under price premiums, the offshore wind farm can nominate its generation first. Then, the TSO bases its interconnector utilization planning on this. Alternatively, under feed-in tariffs, the TSO takes an integrated optimization approach. In a next step, we turn towards basic assumptions before highlighting the main results in the form of a number of propositions. These show the constellations when it could be beneficial for single market actors to bid more or less than expected. Finally, the discussion follows before turning towards the conclusions.

II. Model

In practice, the daily operations of electricity markets are processed in several time steps: day-ahead markets close at noon and following schedule corrections can be done on intraday markets. The remaining deviations from schedules are managed by balancing schemes and the activation of reserve power plants and other resources available for TSO balancing in real time. Depending on national market design and conditions, the bulk of wind power corrections is handled via intraday markets (e.g. in Germany) or via balancing/regulating power markets (e.g. in Denmark). In this paper, intraday and regulating schemes are subsumed as ‘correction markets’, assuming that their prices should converge to some point. In addition, they share the characteristics that their flows over international interconnectors do not yield congestions rents for the TSOs. Thus, the following steps constitute the framework for wind integration and power trading in an offshore grid:

1. Expected wind generation can be nominated by the responsible party to reserve a share of the transmission capacity.
2. The day-ahead spot market closes and planned flows on interconnector capacity are determined by implicit auctions.
3. Adjustments of expected wind generation are handled on correction markets. These may also allow corrections between onshore zones, i.e. offshore wind deviations are not necessary to change the planned flows.

The terms 'country' and 'zone' for a power market area are used synonymously in this paper. In the following, the authors distinguish the economic framework for the involved actors under a) a premium scheme for the support of the offshore wind farm or b) a fixed feed-in tariff scheme. In both cases, it is assumed that the income for the offshore wind farm is identical (i.e. market income plus premium income correspond to feed-in tariff income). In the first case, the wind farm is responsible for marketing its generation, including correction measures from deviations from the plan. In the second case, the wind farm receives a fixed income for all its generation and the responsibility of wind imbalances management is delegated to the TSO. In this case, the TSO becomes the universal manager of the offshore grid that needs to weight congestion rent income from trading with marketing wind power. Note that 'TSO' is used as a term for a common TSO managing the whole offshore grid. In reality, there might be conflicts of interests if several TSOs are involved in such a network and its operation.

In the following, this subchapter is structured according to 3 electricity market design options (also used in a different context by Phulpin and Ernst, 2011) and 2 support mechanism options. The electricity market options are first, the benchmark case where an offshore wind farm (OWF) solely belongs to one country (Figure 1). In the second case, the offshore wind farm is part of an offshore grid, yet placed in its home country's national electricity market (Figure 2). This implies that if physical constraints allow, national electricity market prices apply. If the congestion situation is such that this is not possible, the neighbouring electricity markets are accessed. The third case is illustrated in Figure 3: the offshore wind farm is in a neutral price zone between the riparian power market zones. These three regulatory setups can be combined with with two most prominent cases for support schemes, feed-in tariffs and price premiums. Under feed-in tariffs, the TSO administers all forecast errors, whereas the OWF is responsible of doing so under price premiums. In principle, the price premium scheme covers Tradable Green Certificate schemes as well because they share the same characteristics for day-to-day operations.

A. Price premium support

1) Standard national connection

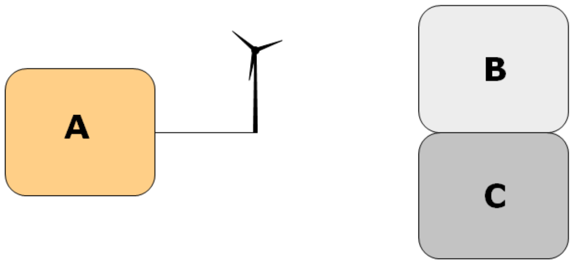

Figure 1: Benchmark case: connection to a single market area

The OWF is connected to only one national market (A). This is the benchmark case and illustrated in Figure 1. Under feed-in tariffs without balancing responsibility, the OWF merely maximises power production because it is remunerated per produced energy unit (MWh). Under more market-integrated feed-in premiums, the OWF is subject to balancing responsibility and its profit function is as follows:

$$\begin{aligned}\pi_{OWF,1} = {} & X_{spot,OA} \cdot Q_{spot} \cdot p_{spot,A} \\ & + X_{corr,OA} \cdot Q_{corr+} \cdot p_{corr+,A} \\ & - X_{corr,AO} \cdot Q_{corr-} \cdot p_{corr-,A} \\ & + (Q_m + Q_{corr+} - Q_{corr-}) p_{prem}\end{aligned} \quad (1)$$

O denotes the offshore location, so if $X_{m,OA}=1$, the interconnector from O towards A is available for market m. The formula considers income from spot markets in the first line as well as from intraday and regulating power markets (which are subsumed under $p_{corr,A}$). If actual generation exceeds the generation that was bid into the spot market, it is sold on these markets at $p_{corr+,A}$. The level of this price depends on the system state in country A: if the imbalance is opposite to the system deviation, the OWF receives a higher income than if it is in line with the system deviation (i.e. partially responsible for the system deviation). The third line of the formula refers to negative deviations: if actual generation is below generation sold on the spot market, this is corrected at respective correction costs $p_{corr-,A}$. Again, the price level depends on the system deviation of country A. Finally, the last part of the formula denotes that the net generation sold on different markets is supported by the price premium. Zugno et al. (2010) give an example for optimal bidding in their case study for Denmark.
The ability to participate in all respective markets of zone A is thus only limited by the availability of the interconnector ($X_{m,OA}$). In general, interconnector availability has a time and a directional component: after the OWF has nominated their expected generation and the spot market is closed, the interconnector may be congested in one direction. This implies that it is still able to provide negative corrections in this direction, as well as positive in the opposite direction.
Regarding wind power, we assume that all generation and following forecast errors are traded on the available markets. The alternative is to judge the economics of wind power also based on portfolio effects and include benefits that are not always covered by the time structure of markets. An example for this case is that wind generation can be combined with ramping of thermal power plants at more flexible time steps than defined by the respective markets.
Trivially, the TSO does not receive any congestion rents from an interconnection with neighbouring zones ($\pi_{TSO,1} = 0$).

2) Offshore grid, national rules apply

In this case, the offshore wind farm has a number of additional connections to other power market zones j. In Figure 2, this is illustrated with the example of three connections in total (i=3). This custom for i and j will be kept for the remainder of the paper. We assume that, if technically possible, all market values of the affiliated zone A apply. Only if the access is limited by congestion or impossible due to an interconnector failure, the other neighbouring markets are accessed.

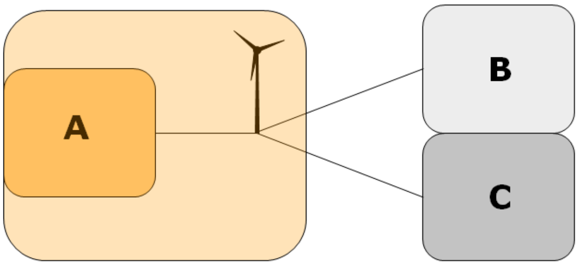

Figure 2: National rules apply in an offshore node

The market sequence and scheduling of international power markets require that

$$
\begin{aligned}
\pi_{OWF,2} = {} & X_{spot,OA} \cdot Q_{spot} \cdot p_{spot,A} \\
& + \left(1 - X_{spot,OA}\right) \max_j [X_{spot,Oj} \cdot Q_{spot} \cdot p_{spot,j}] \\
& + X_{corr,OA} \cdot Q_{corr+} \cdot p_{corr+,A} \\
& + \left(1 - X_{corr,OA}\right) \max_j \left[X_{corr,Oj} \cdot Q_{corr+} \cdot p_{corr+,j}\right] \\
& - X_{corr,AO} Q_{corr-} p_{corr-,A} \\
& - \left(1 - X_{corr,AO}\right) \min_j \left[X_{corr,jO} \cdot Q_{corr-} \cdot p_{corr-,j}\right]
\end{aligned} \tag{2}
$$

$$+ (Q_m + Q_{corr+} - Q_{corr-})p_{prem}$$

$$\pi_{TSO,2} = \sum_{X_{ij}} (1 - X_{ij})\, f_{spot,ij}(|p_{spot,i} - p_{spot,j}|)$$

with $f_{spot,OA} \leq f_{max,OA} - Q_{spot}$ for the connection OA and $f_{spot,ij} \leq f_{max,ij}$ for all other connections.

The first line of the formula denotes that energy is sold at the market prices of zone A. Whenever the connection X_{OA} is not available ($X_{OA} = 0$), the highest price of the neighbouring zones is chosen. For spot markets, this is the market price of the interconnector(s) which are uncongested; for correction markets, it depends on their bid structure.

The same logic of primary market affiliation to zone A applies for forecast deviations: they are regularly traded at zone A's prices. If this is impossible, the OWF chooses to sell positive imbalances at the highest possible price among neighbouring regions. Analogically, negative deviations are corrected for at the cheapest possible price. Finally, the TSO incurs congestion rents, which is the sum of all spot-traded flows over congested lines multiplied with the respective price differential. Because the OWF belongs to country A, its transmission is deduced from the congestion rents.

3) Offshore grid, nodal pricing

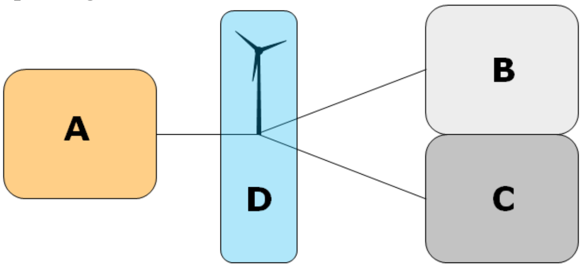

Figure 3: Neutral price area as under nodal pricing

The offshore zone could also be a neutral zone between the neighbouring areas, as it would be under a nodal pricing scheme (see Figure 3). Thus, it constitutes a price zone without any demand units, so the decisive price is determined by non-congested interconnectors. This constellation leads to the following potential profit for the offshore wind farm:

$$\begin{aligned}\pi_{OWF,3} = {} & \max_j [X_{spot,Oi} \cdot Q_{spot} \cdot p_{spot,i}] \\ & + \max_i [X_{corr,Oi} \cdot Q_{corr+} \cdot p_{corr+,i}] \\ & + \min_i [X_{corr,iO} \cdot Q_{corr-} \cdot p_{corr-,i}] \\ & + (Q_{spot} + Q_{corr+} - Q_{corr-})p_{prem}\end{aligned} \quad (3)$$

$$\pi_{TSO,3} = \sum_{X_{ij}} (1 - X_{ij})\, f_{spot,ij}(|p_{spot,i} - p_{spot,j}|)$$

The different parts of formula (3) denote, inter alia, the abilities to correct positive or negative deviations with the neighbouring regions: the first line determines that the spot market income is set by the non-congested interconnectors. The case that the cables *towards* different zones are congested still leaves the possibility that there is a price difference due to congestion *from* one of these zones. This effect is accounted for by the *max* term in front of the spot market income. The second line denotes that positive corrections are sold at the maximum correction price that can be obtained. Finally, the third line stands for acquiring upregulation at a minimum cost and the last line for the granted price premium.

The TSO income is equivalent to the sum of congestion rents from all lines. The difference towards case 2 is that no ‘for-free transmission right’ towards its home country is given to the OWF. This increases congestions rents for the TSO, but is at the detriment of the OWF if all interconnectors have the same capacity (see Schröder (2011) for examples).

B. Feed-in tariff support

In principle, the setup is similar to the earlier discussed price premium setup (see above figures) – with the difference that the TSO is responsible of handling possible imbalances. We assume that the TSO has an incentive to optimise wind marketing, which is why it enters its profit function directly. Then, the situations are as following:

1) Standard national connection

The revenue of the OWF corresponds to the feed-in tariff multiplied with the generation. In this case, the TSO does not have any congestion rent income, but is responsible of handling wind deviations:

$$\pi_{OWF,1} = Q_{FIT} \cdot p_{FIT} \qquad (4)$$

$$\begin{aligned}\pi_{TSO,1} = {} & \mathrm{X_{spot,OA}} \cdot \mathrm{Q_{spot}} \cdot \mathrm{p_{spot,A}} \\ & + X_{corr,OA} \cdot Q_{corr+} \cdot p_{corr+,A} \\ & - X_{corr,AO} \cdot Q_{corr-} \cdot p_{corr-,A}\end{aligned}$$

2) Offshore grid, national rules apply

The revenue of the OWF is as under the standard national connection (see above). By contrast, the TSO’s revenue changes by the wind marketing and correction task:

$$\begin{aligned}\pi_{TSO,2} = {} & \textstyle\sum_{X_{ij}}(1 - X_{ij})\, f_{spot,ij}(|p_{spot,i} - p_{spot,j}|) + \qquad (5) \\ & \mathrm{X_{OA}Q_{spot}p_{spot,A}} + (1 - \mathrm{X_{OA}}) \max_j[X_{spot,Oj} \cdot Q_{spot} \cdot p_{spot,j}] \\ & + X_{corr,OA} \cdot Q_{corr+} \cdot p_{corr+,A} \\ & + (1 - X_{OA}) \max_j[X_{corr,Oj} \cdot Q_{corr+} \cdot p_{corr+,j}] \\ & - X_{corr,AO} \cdot Q_{corr-} \cdot p_{corr-,A} \\ & - (1 - X_{AO}) \min_j[X_{corr,jO} \cdot Q_{corr-} \cdot p_{corr-,j}]\end{aligned}$$

with $\mathrm{f_{spot,OA}} \leq \mathrm{f_{max,OA}} - \mathrm{Q_{spot}}$ for the connection OA and $\mathrm{f_{spot,ij}} \leq \mathrm{f_{max,ij}}$ for all other connections.

3) Offshore grid, nodal pricing

The revenue of the OWF is as under a national feed-in regime (see above). The TSO’s revenue is complemented by the wind marketing responsibility:

$$\begin{aligned}\pi_{TSO,3} = {} & \sum_{X_{ij}}(1 - X_{ij})\, f_{spot,ij}(|p_{spot,i} - p_{spot,j}|) \qquad (6) \\ & + \max_i[X_{spot,Oi} \cdot Q_{spot} \cdot p_{spot,i}] \\ & + \max_i[X_{corr,Oi} \cdot Q_{corr} \cdot p_{corr+,i}] \\ & - \min_i[X_{corr,iO} \cdot Q_{corr} \cdot p_{corr-,i}]\end{aligned}$$

III. Assumptions

For this setup covering offshore wind power, balancing responsibilities and directional congestion issues on interconnectors, a number of assumptions are taken: day-ahead spot markets are the main market, followed by the possibility to participate in correction markets before finally being held balancing-responsible. A positive or negative deviation from the day-ahead plan can be deliberate due to asymmetric bidding, because it increases profit via correction markets. The OWF, in its ability as an alert market observer, has a reasonable expectation for all market price levels. However, the imbalance direction in the different surrounding systems is unknown and not correlated with the OWF's potential deviation (50% for positive and negative system deviations each). For imbalances, the Nordic market model applies: if contrarily to system deviation, imbalances are remunerated at the spot price (see Holttinen (2005) for further details). If it is in line with the system deviation, the imbalance price is charged. Furthermore, the OWF's bids are not marginal in all considered markets, i.e. the price level in all markets is independent of the OWF's bidding behaviour and the TSO's capacity allocation.

The following exemplary case studies partly draw on the concept that power systems dominated by thermal or hydro reservoir power plants have different characteristics with regard to short-run marginal costs. Thermal systems exhibit a larger spread between spot and regulating power markets because fast-starting units with high marginal costs may be required, or because fuel can be saved. In hydro-dominated systems with sufficiently large generation capacity, spot and regulating prices converge (see Figure 4) (see Skytte (1999) for a detailed econometric analysis). Please note that the figure is on price divergence only and does not indicate price levels. In dry years, power prices in the hydro-dominated Nordic system can exceed prices in thermal-dominated Central Western Europe.

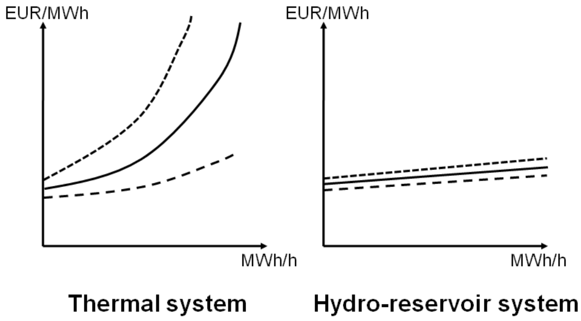

Figure 4: Short-run marginal cost characteristics of different power systems. The middle line represents the spot market price, whereas the upper and lower represent up- and down regulation markets.

IV. Results

The following results are an exemplary overview of interesting constellations in the presented setup (Table 1). Obviously, an analysis of the benchmark case 1 is not necessary because there is no strategic interaction between the OWF and the TSO. For case 2, we analyse both cases with the home and the foreign zones as the high-price areas under a price premium scheme. Regarding interconnector capacities, we consider identical capacities to both neighbouring areas (referred to as a tee-in connection in DeDecker and Kreutzkamp, 2011) as well as different interconnector capacities. The remaining, non-covered case of the other market as a high-price zone under identical interconnector capacities is simpler. The reason for this is that the congestion will under all circumstances occur between the OWF and the other, high-price market without a possibility to access it (see Schröder (2011) for further details). Regarding case 3, identical interconnector capacities do not leave any room for strategic behaviour (Schröder, 2011). For the other possible combination, case 3 with feed-in tariffs, the strategic incentives are partially as for case 2. For this reason, it is not considered separately. There is a large number of possible network topologies and resulting incentives for individual cases. Therefore, the following elaborations are not comprehensive, but highlight the most notable effects that can occur.

Table 1: Overview of case combinations analysed

Proposition	Support scheme	Case	High price zone	Interconnector capacities
1a	Price premium	2	Home market	Identical
1b	Price premium	2	Other market	Different
2	Feed-in tariff	2	Home market	Different
3	Price premium	3	-	Different
4	Feed-in tariff	3	-	Different

Proposition 1a: Price premium, Case 2
Let the spot market price level in zone A be higher than in the neighbouring markets j. The OWF will nominate more spot production than expected if balancing expenses are relatively lower than price difference between A and alternative markets. Vice versa, it may nominate too little if upregulation prices in the other market are comparatively high.

Due to the market timing with a costless nomination right, the OWF can move first. All cables are available for the spot market and the market prices in zone A are expected to be higher than in zone j ($p_{corr+,A} > p_{spot,A} > p_{corr+,j}$). The resulting flow is therefore towards zone A, i.e. formula (2) can be reduced by a number of terms. Then, the OWF optimises

$$\begin{aligned}\pi_{OWF,2} = {} & X_{spot,OA} \cdot Q_{spot} \cdot p_{spot,A} \\ & + (1 - X_{corr,OA}) \max_j [X_{corr,Oj}(Q_{real} - Q_{spot}) p_{corr+,j}] \\ & - 0.5\, X_{corr,AO}(Q_{spot} - Q_{real}) p_{corr-,A} \\ & + Q_{real} \cdot p_{prem}\end{aligned} \tag{6}$$

Both terms $(Q_{spot} - Q_{real})$ and $(Q_{real} - Q_{spot})$ are defined as being equal to 0 or have positive values.

The first part of the formula denotes the income from the spot market. The second term denotes the positive difference between day-ahead announced and real production. If the OWF can produce more than announced, it sells this at $p_{corr+,j}$; depending on the system imbalances in j, this corresponds to the respective spot or imbalance prices. In return, if the production target is not met and positive balancing required, this happens at the market price of zone A (third line). The probability 0.5 entered the line because this is the penalty risk; if the negative deviation is in line with the system deviation, it is billed at the spot market price. Finally, the last term denotes that the premium is granted for the final generation amount.

Based on equation (6), nominating more generation (Q_{spot}) than actually expected is beneficial if

$$\begin{aligned}(Q_{spot} - Q_{real})\,[0.5\,(p_{upreg,A} - p_{spot,A})\,] \; < \\ (Q_{real} - Q_{spot})(p_{spot,A} - (0.5^{\,j} p_{downreg,j} + (1 - 0.5^{\,j})\, p_{spot,j}).\end{aligned} \tag{7}$$

There is a chance of 50% that the system deviation in A is opposite to the OWF's deviation, i.e. that spot market prices apply and thus, the OWF does not face a loss in income. If the remaining 50%

chance applies and the penalty for generating less than announced (upper part) is smaller than opportunity income from correction markets in j (lower part), too much will be nominated. The correction market income is estimated such that system imbalances of the neighbouring systems j are independent of each other. This implies that with a higher number of neighbouring systems j, it is more likely $\left(1-0.5^{j}\right)$ that one of their imbalances is opposite to the OWF's and therefore, the respective spot market applies. In practice, this situation would typically apply if A is a hydro system and j are thermal-dominated systems. If we assume that the OWF could actively contribute to upregulating power markets with higher market prices than spot markets, the picture changes: if upregulation in zone(s) j is more valuable than both its and zone A's spot market values ($p_{upreg,j} > p_{spot,A}$), the OWF may nominate too little to open the access to this market.
In the case of excessive capacity reservation, the TSO's income from congestion rents is affected negatively. Congestion rents are the main socio-economic component in this setup. Under most market constellation scenarios, the overall effect of strategic bidding is negative.

Proposition 1b: Price premium, Case 2
The situation is as above, but with a reversed power market price situation (price in A lower than in j) and with different interconnector capacities. In this case, it may be beneficial for the OWF to nominate less than expected.

Let the interconnector between A and the OWF be smaller than the sum of interconnectors towards zones j ($X_{AO} < \sum X_{Oj}$) and $p_{corr-,j} > p_{spot,A}$. In case of excess generation, the correction price of A applies to the OWF. Contrarily, in when the OWF is short, is has to buy the respective amount at the higher prices of zone j. Furthermore, TSO congestion rents between the OWF and zones j decrease. In conclusion, while the market price is higher in zone A (proposition 1a), the OWF will likely nominate more generation than expected to ensure access to this market. The situation is different under higher prices in j (proposition 1b) and different interconnector capacities.

Proposition 2: Feed-in regime, Case 2
The OWF is in the thermal system A. There is a price spread between a thermal system (high price) and a hydro system (low price). Connections to other zones are far larger than towards A. If the TSO is profit-maximising, they will prefer to nominate too little wind in order to incur higher congestion rents and avoid higher charges for negative imbalances.

As the TSO is assumed to be obliged of handling all imbalances, it may have to sell positive imbalances of the OWF at lower than spot market prices. If too little wind is bid, the outgone profit is mainly the difference between A's spot market price and j's correction market price (which is close to the spot price in the hydro system). In this setup, the outgone profit from bidding too little wind into the high-price zone A corresponds basically to the additional congestion rent income. By bidding too little, the chance of facing the high imbalance charges in A is reduced. The general formula is adjusted to reflect this and concentrates on the connection between A and the OWF only:

$$\pi_{TSO,2} = (f_{max,OA} - Q_{spot})\left(\left|p_{spot,A} - p_{spot,j}\right|\right) - X_{corr,AO} \cdot Q_{corr-} \cdot p_{corr-,A} \qquad (8)$$

Maximisation is chiefly about balancing these terms: congestion rent income versus additional expenses for buying positive imbalances of wind energy. In this case, $p_{corr-,A} > p_{spot,,A} > p_{corr+,j}$ applies. The reason is a risk asymmetry: if there is less wind than expected, interzonal correction trades will not yield any congestion rent.

For a reversed market situation with the OWF located in a high-price hydro system, the proposition is reversed as well: the TSO tends to nominate more wind production than expected.

Proposition 3: Price premium, Case 3
There is an incentive to nominate less if the OWF can cause a congestion situation that helps itself in moving into a higher-price power zone.

Let there be connections of different capacity between the offshore zone O and the onshore zones A and B ($f_{max,OA} > f_{max,OB}$). The price in A is higher. The OWF spot market nomination determines whether $p_{spot,O} = p_{spot,A}$ or $p_{spot,O} = p_{spot,B}$. Then, by bidding such that $Q_{spot} + f_{max,BO} < f_{max,OA}$, it causes congestion on the interconnector BO and receives $q_{spot,A}$. This is beneficial if $Q_{spot,A}p_{spot,A} > Q_{expected}p_{spot,B}$. Correction market and imbalance regime considerations may be added to these arguments, but seems negligible in view of the spot market choice. TSO congestion rent income is reduced by this choice: the price differential between the markets A and B is constant and instead of multiplying this with the capacity of the large interconnector AO, the smaller capacity BO applies.

In summary, the discussed propositions demonstrate that offshore wind farms face incentives for acting strategically in both case 2 and 3. Excessive capacity reservations reduce TSO income, whereas voluntary curtailment may increase both TSO and OWF income under specific conditions. The two latter propositions show that deviating from traditional nodal pricing rules should be discussed if markets should be designed in such a way that they induce truth-telling.

Proposition 4: Feed-in tariff, Case 3
Under a combined optimisation of congestion rents and OWF generation value, incentives for strategic behaviour are reduced in comparison to proposition 3. Nevertheless, there may be reasons to deviate from bidding the realistic expectations.

When maximizing the overall income from the OWF and congestion rents, the incentive explained in proposition 3 does not exist: if the TSO bids less OWF generation than expected into the spot market to maximize OWF income, it reduces income from congestion rents accordingly because the bottleneck is moved to an interconnector with less capacity (see Figure 6Figure 7 and the respective text for an example).
The second part of the proposition states that there is a tendency for deviating from realistic expectations. This is due to the asymmetry in accessible correction markets. Let us distinguish two cases:
Congestion is between the OWF and the high-price zone A, i.e. to the supplied zone. Then, it is profitable to bid more than expected. For the correction market part of the profit formula, $+ \max_j[X_{corr,Oj} \cdot Q_{corr} \cdot p_{corr+,j}] - \min_j[X_{corr,jO} \cdot Q_{corr} \cdot p_{corr-,j}]$ the j and $X_{corr,Oj}$ represent the uncongested zones, i.e. except A. Positive deviations can only be sold at the lower prices of the surrounding zones. Contrarily, i and $X_{corr,iO}$ comprise all zones: upregulation can either be procured in A (the system that is short due to the shortage of OWF generation) or in the other zones at lower prices.
Congestion is between the OWF and the low-price zone B, i.e. from the supplying zone. Then, it can be profitable to bid less than expected. In analogy to the case above, the price level of this cheaper zone B cannot be accessed if the OWF is short. Instead, upregulation can only be acquired at the higher price level of the supplied country. Excess generation of the OWF can in return be provided to all neighbouring areas.

In fact, this applies also to a price premium regime if the network situation is such that switching between spot price zones is not profitable. Of course, the above considerations are dependent on the different countries' correction price levels and the optimal solution may be different for specific constellations of markets with thermal or hydro characteristics. The argument's core is that neighbouring zone's correction markets become partially unavailable to the OWF.

V. QUANTITATIVE CASE STUDIES

In the following, we assume that the OWF is located between only two neighbouring zones. All possible imbalance combinations (both zones short, both zones long, A short/B long and vice versa) occur with an equal likelihood of 25%. Table 2 gives an overview of the main quantitative assumptions.

Table 2: Quantitative assumptions for case studies

	Value	Unit
High price market	60	€/MWh
Low price market	40	€/MWh
Excess generation (if in line with system deviation)	-5	€/MWh in comparison to spot market
Lacking generation (if in line with system deviation)	+10	€/MWh in comparison to spot market
OWF realised generation	1000	MWh/h
Price premium	0	€/MWh

Deviating from this, for proposition 1b, negative imbalances that need to be bought in zone B in line with the system deviation are at +40 €/MWh in comparison to the spot market. For proposition 2, the price deviations for the hydropower market are smaller than for the thermal-dominated market.

Figure 5 gives an overview of the outcomes. The OWF faces a natural variability. Here, we assume that this variability is adjusted by 100MW up- or downwards. An example for this is that if 800 MW were expected, only 700 MW are bid if bidding less is supposed to be beneficial. Finally, 1000 MW are realised.

Figure 5 displays the outcomes for the different actors under truth-telling (benchmark) and the suggested strategies. Under proposition 1a, the OWF's spot market income increases by approx. 10% in comparison to the benchmark case (bidding real expectations). Expenses due to balancing increase as well, but less than 10%. Overall, because spot market income is dominant, this implies a 1.5% gain for the OWF and a 50% loss in congestion rents for the TSO. For proposition 1b, a decrease in spot market income is outweighed by savings in balancing expenses. In total, this leads to a 6.5% higher income for the OWF with the exemplary numbers. Congestion rents are reduced by 5%. Nevertheless, the additional profits of the OWF are higher than the TSO's reduced income. Regarding proposition 2 with the feed-in tariff, the TSO is the only actor. By bidding less, it reduces spot income, but compensates this by higher balancing and congestion rent incomes. In sum, its revenue increases by 0.6%.

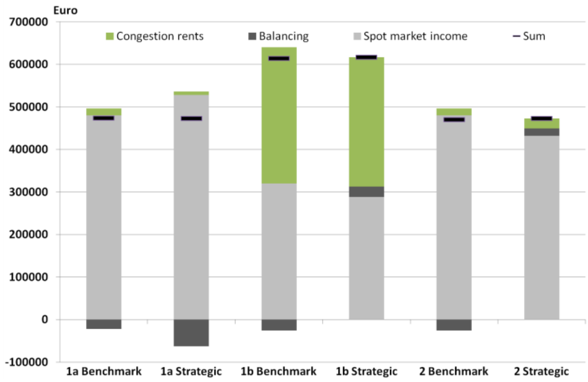

Figure 5: Deviations between the strategic bidding and a respective truth-telling strategy

Finally, a graphic example of the network situation illustrates proposition 3 best. Let us assume that the OWF expects a generation of 1000 MWh for the regarded hour.

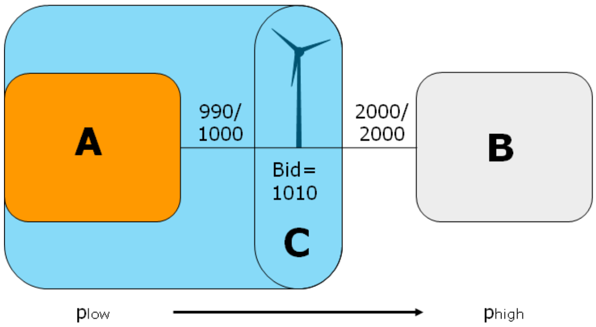

Figure 6: Market affiliation for wind bids > 1000 MW

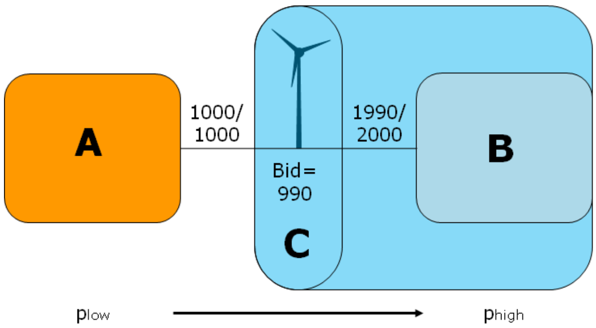

Figure 7: Market affiliation for wind bids < 1000 MW

The network configuration is displayed in Figure 6: there is one connection of 1000 MW towards country A and one connection of 2000 MW towards country B. A is the low-price zone (40€/MWh) and B constitutes the high-price zone (60€/MWh). Therefore, the flow direction is given exogenously. Let us now regard two close-to marginal option:

1. Figure 6: by bidding 1010 MWh, the OWF moves the congestion between itself and B (2000/2000 MW planned flow). In this case, it has a spot market income of 40400 € (40€/MWh x 1010 MWh), Furthermore, it expects that it has to acquire imbalance power for its expected imbalance of 10 MWh (for simplicity, it is assumed that correction market prices are equal to spot prices). Because the cable from country A is not congested, it can do so at the low prices applying there. TSO congestion rents for this case are 40000 € (2000 MWh x (60-40) €/MWh).
2. Figure 7: the OWF bids less than expected, e.g. 990 MWh. By doing so, it moves the bottleneck on the interconnector from A towards C. Congestion between C and B is relieved, which is why it forms a common price zone. The OWF has therefore an income of 59400 € (60 €/MWh x 990 MWh). The expected imbalance of 10 MWh can be sold at the correction market price level of zone B, which can expected to be higher than in zone A. At the same time, the TSO's income is reduced to 20000 € (1000 MWh x (60-40) €/MWh).

Table 3: Strategic bidding outcomes under nodal pricing with price premiums

	Option 1	Option 2
Wind bid	1010 MWh	990 MWh
Spot market income	40400 €	59400 €
Correction market income	-400 €	+600 €
Income from wind activities	*40000 €*	*60000 €*
Congestion rents	40000 €	20000 €
Overall surplus	*80000 €*	*80000 €*

This case comparison illustrates clearly that the OWF can benefit from strategic bidding (see Table 3 for an overview). By choosing strategy (2), it can improve its spot market income by about 50% in this example. Of course, the same considerations about imbalances than in the other propositions apply. In practice, however, being able to switch between different spot market prices is expected to by far outweigh strategic considerations due to imbalances. The case illustrates that the OWF's behaviour can diminish TSO congestion rents accordingly. If the price premium given to the OWF is constant, this is a suboptimal outcome from a socio-economic point of view. If the support is adjusted downwards accordingly to reflect the benefit from strategic acting, the two cases are virtually equivalent from a socio-economic point of view for this marginal case. This is not the case for non-marginal cases that are still attractive for strategic behaviour of the OWF: OWF profits and TSO losses compensate each other at the spot market time horizon, but not afterwards. Because it bid less, the systematic excess generation can be sold at the lower prices of zone A. This is an additional income to the OWF. If not compensated for by adjusting financial support accordingly, this may imply a distributive effect that is undesirable from a socio-economic point of view.
The above example for proposition 3 illustrates the case for proposition 4 as well: the TSO considers both wind income and congestion rents and thus, the overall surplus is identical (Table 3). This is based on the assumption that correction market prices are identical to spot market prices. If this assumption is relaxed, bidding a different generation than expected into the spot market, as also

stated in proposition 4, could be attractive. Then, the incentive structure is similar to case 2, which is why it is not elaborated in further detail here.

VI. Discussion and Conclusions

This paper provides a conceptual and analytical framework for the major effects and incentives for offshore wind farms and TSOs under a price premium and a feed-in tariff scheme. It demonstrates that specific strategic incentives can evolve in offshore grids and that these can lead to suboptimal asset utilisation. Three cases are contrasted: as a benchmark the standard national connection, as a first alternative, an offshore location in a meshed grid affiliated to a country and finally, an independent offshore zone. The authors think that these are the main options that will be considered for offshore grids, with the third one entering the picture at a longer time scale. Furthermore, feed-in tariffs and price premiums represent the main support options, also in the case where the level of support is decided upon by tendering.

The presented study assumes a certain affiliation of tasks for the OWF and the TSO, and an integrated TSO instead of several independent ones. This task allocation may be designed differently, with incentives defined such that desired outcomes are achieved, and TSO may have to compensate wind generators under a feed-in tariff if these cannot generate due to imposed restrictions. This paper seeks to provide some suggestions on this path. Obviously, the presented model includes some simplifications, e.g. the assumption that the state of the offshore grid only touches the neighbouring markets marginally. This leads also to the limitation that onshore consumer and producer surpluses are not affected via price changes. We highlight some examples and demonstrate effects that could occur; if a full picture for a real situation is to be gained, it would be necessary to look at a number of market parameters and analyse all possible scenario constallations. The quantitative cases are rather rough, exemplary approximations that do not allow conclusions on a realistic magnitude of the effects. This would also be too detailed at this very early stage of offshore grid development; their purpose is to illustrate the existence of the effects.

The authors would like to stress the criterion that offshore grids are supposed to complement the establishment of offshore wind farms. This implies that offshore grid market design should be such that it does not impose an additional risk for advanced project plans. Otherwise, the erection of offshore wind farms and thus, the precondition for the establishment of a meshed offshore grid may be hampered. We need to have a closer look whether the responsible entity should be forced to always bid its expected wind generation into spot markets; deviations may be positive for a single actor, but limit TSO income and socio-economic benefits. Under certain circumstances, however, they may also be beneficial for all involved entities. Complementing the recommendations made by Neuhoff and Boyd (2010), we conclude that an integrated approach of wind bidding and transmission asset management is crucial for offshore grids.

With regard to balancing group design, a special balancing group may be required due to possible instances of congestion in case 2. The design may be such that it is compulsory to follow national prices whenever possible. Benefits or disadvantages due to participation in other countries' balancing markets could be compensated for. In practice, this could be handled through regular add-ons or reductions of support payments. This market design furthermore implies that cross-border flow plans need to be adjustable because the OWF can in some instances receive up- and down regulation only from a specific country.

Under nodal pricing, intraday and balancing market adjustments of planned cross-border flows are a necessity if an offshore balancing group exists. An alternative approach is to allocate the OWF generation always to the operator's portfolio in the country with highest power prices. This would represent priority dispatch of wind energy and requires that the OWF operator is a balance responsible party in all surrounding countries. However, this causes very high positive balancing costs for the OWF if it is short and balancing markets are not integrated.

Other implications of the investigated cases are that under a national market affiliation, an OWF has an advantage if it is the only entity with access to all neighbouring regulation markets and imbalance schemes. This would decrease if neighbouring balancing markets are integrated and therefore, their deviations correlate. However, this approach seems very promising from a socio-economic point of view because buying regulating power of opposing directions in neighbouring zones is avoided.

It has furthermore been shown that under asymmetric interconnector capacities, nodal pricing and a price premium scheme, the OWF has an incentive to withhold generation because that way, it can move into a higher-price zone. If, as a remedy, it should be decided that the offshore location always receives the maximum income of the neighbouring zones, the corresponding reduction in necessary support should enter the TSOs' socio-economic considerations. If the TSO is responsible for both feed-in tariff management and congestion rents, it should be ensured that a combined optimisation attributes the monetary streams to the right customer groups in order to avoid wealth transfers.

In conclusion, two approaches could be pursued: under price premiums with strategic incentives for the offshore wind farm, the support should be adjusted accordingly to reflect the benefits of strategic behaviour. This, of course, leads to a classical principal-agent information asymmetry when reflecting these benefits in the policy scheme. Alternatively, guaranteeing a fixed income to offshore wind farms and pursuing a co-optimisation of wind bidding and congestion management could be chosen. This would also ensure appropriate investment incentives for TSOs because the value of the interconnection cannot be diminished by strategic actions of third parties. In summary, leaving both wind and congestion management to the TSOs seems the most promising approach for future meshed offshore grids.

VII. ACKNOWLEDGEMENTS

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VIII. NOMENCLATURE

Abbreviation	Explanation	Unit
π_{OWF}	Profit of the offshore wind farm	EUR
$f_{m,ij}$	Flow between zones scheduled	MWh
$i, j = A, B, C, \ldots$	Power market zones; O: Offshore zone	-
$p_{m,i}$	Market price in zone i	EUR/MWh
$p_{spot,i}$	Day-ahead spot market price in zone i	EUR/MWh
$p_{corr\pm,i}$	Respective correction market price in zone i for positive and negative imbalances	EUR/MWh
$p_{prem,i}$	Price premium scheme in zone i	EUR/MWh
t	time period	h; 8760h/year
Q_m	Offshore wind farm	MWh

	generation bid into the respective market	
$X_{m,ij}$	Binary: Interconnector between market zones i and j available for additional power flow (if X=1)	-

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– Appendix III –

The impact of an offshore electricity hub at Kriegers Flak on power markets

Sascha T. Schröder, Helge V. Larsen, Peter Meibom
Proceedings of the European Wind Energy Conference 2010, Warsaw

The impact of an offshore electricity hub at Kriegers Flak on power markets

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Abstract

The combination of offshore wind generation with offshore interconnectors between different national markets receives much attention lately. The most mature project is Kriegers Flak between Sweden, Denmark and Germany. All countries consider the installation of 400-600 MW of generation capacity in proximity to each other. A pre-feasibility study by the respective transmission system operators reveals socioeconomic benefits from extending this solution to an offshore interconnector hub. The solution is supported by the EU, which envisages financial aid under the economic recovery programme. This paper seeks to investigate the effects of such a solution on the surrounding power markets by introducing the different suggested designs in the WILMAR model for 2015, regarding the Nordic and central European power markets. This linear optimisation model with an hourly resolution has already served for a number of other studies, e.g. Tradewind and EWIS. The four different topologies suggested in the pre-feasibility study are implemented in the model: the benchmark case represents the inclusion of offshore capacity in the respective national markets. The second case assumes national connections to the offshore hub at the nominal capacity of the national offshore capacity, whereas the third excludes German generation and connects Germany with a separate cable to the offshore node with Danish and Swedish generation. This setup has been chosen to account for difficulties with German market regulation. The fourth case extends the available capacity between Germany and the offshore hub considerably. It is assumed that wind variability is parallel in the three national offshore parks due to their geographical proximity. The modelling results allow assessing the operational costs in the system as well as the revenue streams for the transmission system operator and the offshore wind operator under different market designs. Namely, considering the offshore hub as a single price zone for the aggregate generation leads to a different outcome than under an affiliation to national markets. The resulting benefits of the topologies tend to increase with more transmission capacity between the German and the Swedish system. Especially in this light, the consequences of latest changes indicating a postponement of the Swedish wind farm and interconnector should be assessed in detail.

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1. Introduction

There is an international consensus that additional electricity generation from renewable energy sources (RES) is desirable due to several reasons, notably climate neutrality, energy security, and long-run economic aspects. After many years with large growth rates of onshore wind installations, offshore sites are approaching economic viability. At the same time, different fluctuating RES at different locations pose the issue of spatial levelling at a large scale. The nowadays most prominent proposal has been forwarded by the DESERTEC consortium (www.desertec.org) and suggests extensive solar installations in Southern Europe and Northern Africa as well as wind generation in Northern Europe. The existing electricity transmission network needs substantial reinforcement to connect generation with demand and to allow spatial levelling of fluctuating RES over a wide geographical area. This levelling is also promising with a stronger geographical focus on Northwestern Europe. A number of studies are suggesting different topologies for a possible offshore grid in the North Sea, the most well-known being “Oceans of Opportunity” by the European Wind Energy Association [1]. The underlying stream of thought is that offshore wind farms require interconnectors to the shore. At the same time, the increasing European electricity market integration calls for more international interconnectors. Especially for different national offshore wind farms in close geographical proximity, connecting them and using the interconnector capacity also for international trading is a promising concept. This paper deals with the first offshore hub where this might come true: at Kriegers Flak in the Baltic Sea, Denmark, Sweden and Germany are considering the erection of wind farms. The hydro-dominated Scandinavian and the thermal-dominated German electricity system exhibit different price patterns. Thus, additional interconnector capacity between them is interesting both from a commercial and a system-operation point of view. The European Council considers furthermore supporting a combined solution at Kriegers Flak with 150 Mill. Euro under the economic recovery plan [2].

2. Historical development and inclusion in models

Kriegers Flak is included in the TradeWind project (www.trade-wind.eu) that assesses the large-scale integration of wind energy in European power markets. The underlying models used are PSST (Power System Simulation Tool) and the WILMAR planning tool. The main data for spatial and temporal wind correlations originates from the Reanalysis project. TradeWind covers different scenarios. For Kriegers Flak, it is assumed that 455MW are installed in the Danish zone by 2013 and 640MW in the Swedish one [3]. Germany follows a modular approach with 183.6MW by 2011 and 145MW by 2013. The corresponding grid infrastructure is a 455MW line from Kriegers Flak to the Eastern Danish electricity system and a 1000MW line towards both Germany and Sweden.

More project-focused work on an offshore electricity hub at Kriegers Flak was issued with a pre-feasibility study by the three involved transmission system operators (TSOs) in 2009 [4]. It entails a wide range of issues that need to be clarified, ranging from technical issues to economic feasibility and market-regulatory questions. In close temporal proximity, the European Council expressed a willingness to support a combined solution at Kriegers Flak under the economic recovery package. A feasibility study with updated and more elaborate economic figures on different design options followed in February 2010 [5]. It included also the central news that the Swedish TSO has withdrawn from engaging in the project within the next years, but will follow planning and might join a modular approach at a later stage. Despite this change, the European Council is in principle willing to support a Danish-German solution with the amount mentioned above. A final political decision on the erection of the Danish part of generation capacity will only be taken in the course of 2010, but can be considered highly likely. Table I provides an overview of the historical development of planned generation capacities.

TABLE I
DEVELOPMENT OF OFFSHORE GENERATION CAPACITY PLANS OVER TIME IN MW

	TradeWind	Pre-feasibility study	Feasibility study	March 2010
Germany	328.6	400	400	<300
Sweden	640	600	600	-
Denmark	455	600	600	600

Figure 1 displays the four topologies suggested in the pre-feasibility study:

A. This is the benchmark case: all three wind parks are connected to their respective countries with a transmission capacity corresponding to the wind farm’s capacity, either by AC or HVDC interconnectors.
B. An AC-solution with an offshore hub at Kriegers Flak. As the former Nordel and the former UCTE systems are not synchronous, a so-called back-to-back converter station is required on the German side.
C. Reasoning that German planning is quite advanced, the German connection passing over the Baltic 1 offshore wind farm is kept as a separate radial connection. Germany, Denmark and Sweden are connected to Kriegers Flak by HVDC lines of 600MW each.
D. As option C, but with the AC line from Baltic 1 prolonged to the offshore hub, where also the German wind park is connected. Trading capacity to Germany is thus enlarged to 1000MW.

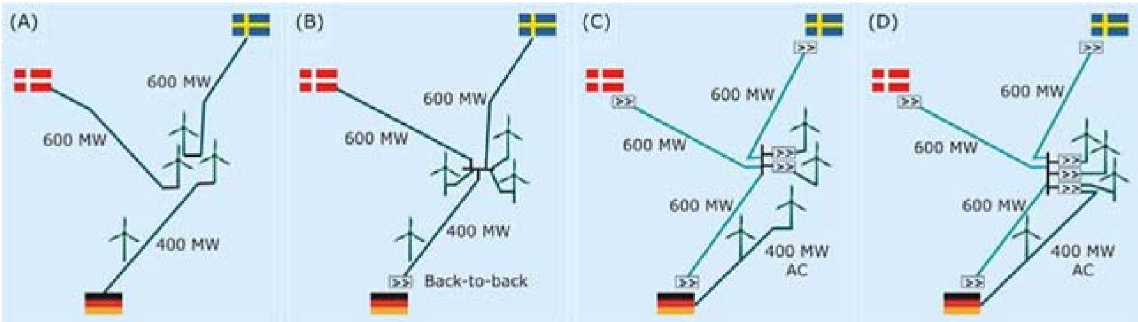

Fig. 1. Four topology cases considered at Kriegers Flak. AC cables are shown in dark blue and DC cables in light blue. [4]

The three national offshore wind sites are visualised in the centre, whereas the additional wind farm closer to the German shore represents Baltic 1. According to German planning, Baltic 1 and Kriegers Flak are to be connected via a common corridor.

In the following feasibility study, scenario C is dropped. Scenario A is modified by combining it with a 600MW interconnector between Germany and Sweden or Germany and Denmark. For scenario D, four different price assumption scenarios are computed.

The first calculations, published in the pre-feasibility study, are based on the EMPS (EFI's Multi-Area Power Market Simulator) model and World Energy Outlook 2008 fuel price assumptions. EMPS simulates the electricity markets of several regions with storage possibilities through a certain share of controllable hydropower [6]. The model optimizes generation from thermal and hydropower plants, also considering wind power generation. The time stepping is weekly, with a duration curve representing fluctuating demand patterns. Hence detailed operation restrictions of thermal power plants and stochasticity of wind are not taken into account. The model can be operated over a 25 year time period.

The feasibility study's calculations are based on EMPS runs and BID model runs. The latter model is provided by a consultancy and provides an hourly resolution.

3. Model and data

The WILMAR planning tool (Wind Power Integration in Liberalised Electricity Markets) optimizes the operation of a power system with a focus on fluctuating wind energy. The time resolution is hourly, and the calculation period is up to a year. For wind power production forecasts, a perfect forecast without forecast error, a single forecast or several forecasts per region can be part of the optimization. The latter cases are based on the Scenario Tree Tool of the model, which calculates wind power production forecasts, load forecasts and demand for positive minute reserves as scenario trees. The Joint Market Model uses these data as input for the power system optimization. The geographical extension is Europe-wide; for further details, see e.g. [6],[7]. In this paper the model is run using deterministic forecast errors.

Fig. 2. Geographical scope of the simulation, in analogy with [4]. The arrows indicate the offshore node at Kriegers Flak.

The geographical coverage of the model runs is illustrated in Figure 2 and is identical with the assumptions from the pre-feasibility study.
Basic assumed parameters are shown in Table II. Fuel prices are significantly higher than in the World Energy Outlook 2007, but not as high as those from the World Energy Outlook 2008. This can be considered as a solid, yet conservative base for the following calculation results. Furthermore, fuel taxes are assumed to be nonexistent and the assumptions for transmission grid reinforcements are in line with EWIS assumptions [8]. The above mentioned wind capacities at Kriegers Flak are added to this and the offshore node is simulated as a separate country. This implies that the price is always close to the one of neighbouring countries if lines are not congested. The pricing mechanism in an offshore price zone without any demand has been discussed in [9].

TABLE II
MAIN PARAMETERS (MONETARY VALUES IN 2005 LEVELS)

	Unit	Denmark-East	Sweden	Germany
Demand	TWh	16.8	165.7	578.9
Fuel oil	Euro/GJ	18.5	18.5	18.2
Coal	Euro/GJ	4.1	4.2	4.1
Gas	Euro/GJ	10.9	10.9	10.6
CO2	Euro/t	25	25	25

Treatment of large hydropower reservoirs requires optimisation of the use of water over a yearly or longer time horizon. The model simplifies this decision problem using a historical time series for the optimal hydro reservoir level in each region during the year. The model reduces the opportunity costs for using hydro power when the reservoir level in the model becomes higher than the historical optimal level and the opposite when the reservoir level becomes lower than the historical level. This ensures that the historical optimal reservoir level during the year is followed closely in the model.

4. Results

The main results from the model simulations are presented in this section. First, the overall socio-economic outcome under the different scenarios is addressed. This can be compared with the private-economic results, where the assumption of the separate offshore price zone is contrasted with the need to transport a share of the generation at Kriegers Flak without obtaining a congestion rent. Finally, the impact on CO2 emissions and on power prices in the respective regions is addressed.

The socio-economic improvement can be assessed by comparing the full system operation costs of the different options. Considering the nationally separate solution A as a benchmark, option B gives an advantage of 22 Mill. Euro, C of about 34.7 Mill. Euro and D of about 43 Mill. Euro (2005 values). These values are after the crucial correction for different usage of hydropower in the different scenarios.

TABLE III
ANNUAL CONGESTION RENTS IN MILL. EURO (2005)

Case	Trading only	Trading - wind generation
B	40.4	17.5
C	47.7	19.4
D	51.1	31.7

From international power trading on an interconnector, income for the line owners is generated. This can be either via explicit auctions, i.e. that the capacity is sold in daily or hourly auctions, or via implicit auctions where the involved power exchanges determine interconnector usage. These are envisaged for Kriegers Flak because they have proven to be more efficient. The congestion rent is calculated as follows: whenever the line is congested, the interconnector owners obtain the price difference multiplied with the capacity of the interconnector. The respective values are displayed in Table III. If the Kriegers Flak offshore hub is calculated with its full capacity, thus multiplying all congestion and price differences, between 40 and 51 Mill. Euro (2005) could be recovered every year. However, in the benchmark case, there cannot be congestion between the offshore wind farms and their respective countries. In other words, for non-discrimination reasons and better comparability, the production of the national wind farm that is imported should be deducted from the imported power. This leads to the values in the column denoted as trading minus wind generation. The congestion rents are between 17.5 and about 32 Mill. Euro (2005) per year.

Figures 3, 4 and 5 allow having a closer look at the directions of power flows and congestion under the different cases. Note that they are directly comparable with Fig. 2-4 of the feasibility study [5]. For all three cases, congestion from Kriegers Flak to East Denmark is present in more than 1000 hours per year. The following part of the curves is declining slowly, and the number of flows or even bottlenecks from Denmark towards Kriegers Flak is small to negligible. The situation for the interconnector to Germany is different: in all cases, there is a considerable amount of congestion in both directions. In all cases, the interconnector is congested in more than 40% of the year. This value holds also for the interconnector to Sweden under topology B. Contrarily, D leads to a congestion quote of over 60%. In comparison, it can be concluded that the connection between Sweden and Germany displays the most pronounced flow patterns. In all cases, over 40% of congestion rents stem from the Swedish line.

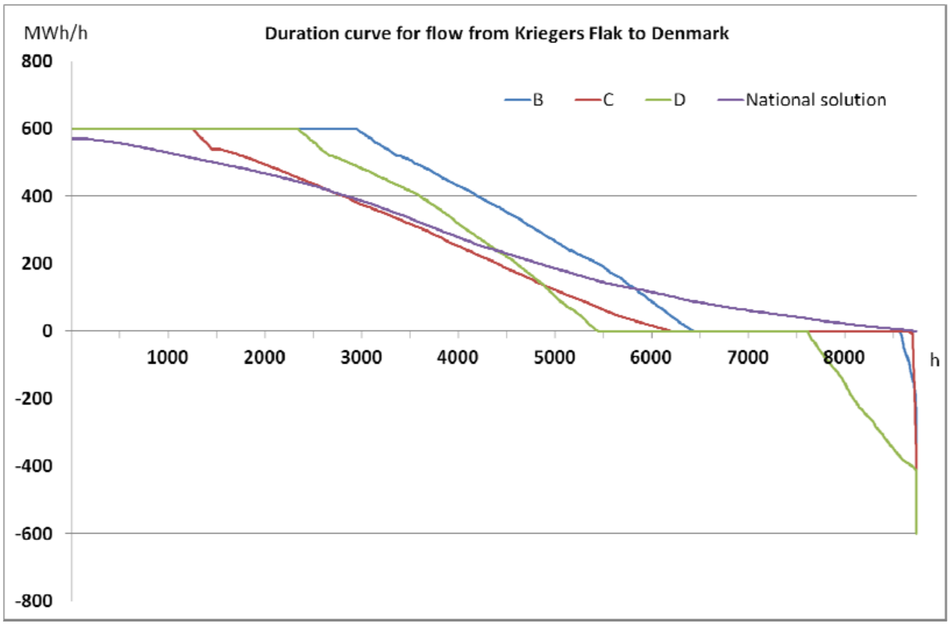

Fig. 3. Duration curve for flow from Kriegers Flak to Denmark.

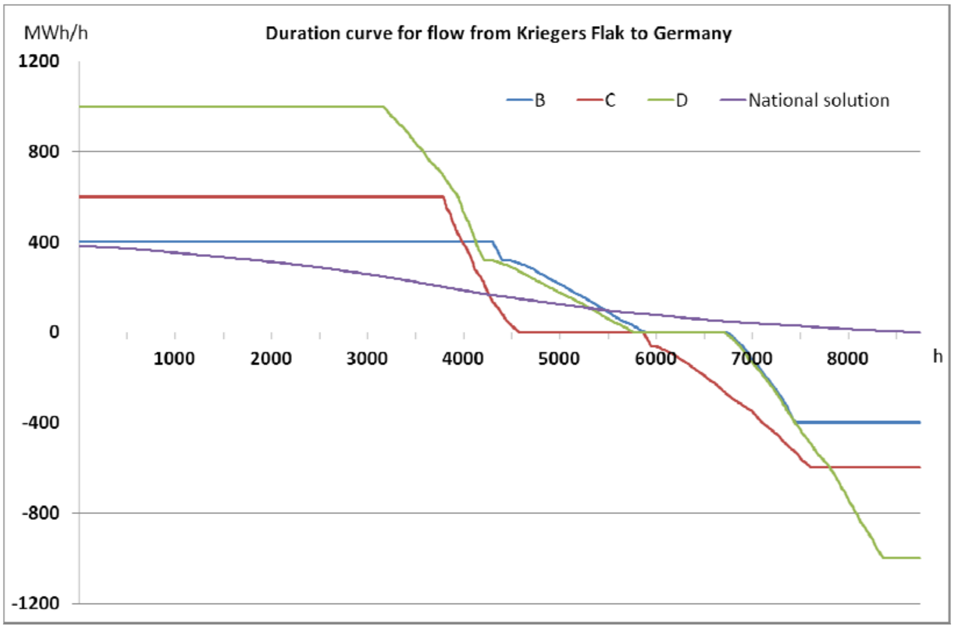

Fig. 4. Duration curve for flow from Kriegers Flak to Germany.

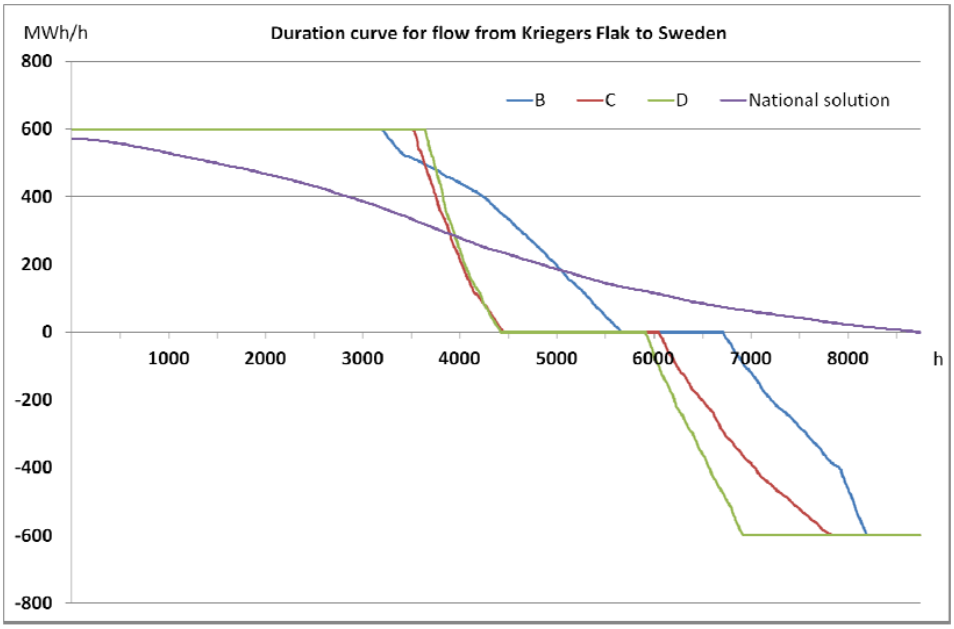

Fig. 5. Duration curve for flow from Kriegers Flak to Sweden.

Cases C and D lead to a reduction of CO2 emissions within the chosen geographical scope of about 0.04%, whereas the value for case B is only at one tenth of this value.
The impact on power prices is only illustrated for the involved countries and only for case D. Based on the assumption of the absence of market power, case D leads to a decrease of power prices by 0.11 EUR/MWh in Germany. In Denmark, prices increase by 0.18 EUR/MWh and in Sweden by 0.76 EUR/MWh. Increased hydropower utilization contributes to the latter.

5. Discussion

The presented results show that economic advantages can be expected from both a socio-economic and a private-economic point of view. The duration curves for power flows on the different interconnectors exhibit the same patterns as those from the feasibility study. However, the wind energy that needs to be transported onshore for free reduces the private-economic congestion rents considerably. [5] estimates the necessary investment sums at about 420 Mill. Euro for option B and about at least 460 Mill. Euro (2010) for option D. The annual economic gains correspond to about a tenth of these values. This shows that offshore hub solutions, especially at longer distances offshore, do have a remarkable potential. Seen in an isolated perspective, the investment decision for Kriegers Flak depends on the responsible TSO’s return expectations and alternative projects. The European Council expressed a willingness to give economic support of 150 Mill. Euro to an integrated solution at Kriegers Flak for different reasons. The most notable is to regard it as a test case for further offshore grid development in the North and the Baltic Sea. Including this support, investing in Kriegers Flak – possibly in the largest option – is positive. However, the beneficiality of the integrated solution seems to depend strongly on the capacity between Sweden and Germany. With the postponement of the Swedish offshore wind farm and interconnector and the decrease of the German park and line from 400 to 300 MW, a careful assessment of the new situation seems necessary. In every case, planning should be done in such a way that the solution can be upgraded to one resembling case D.
The above results show that a separate offshore price zone at Kriegers Flak and using the full interconnector capacity for trading leads to higher income from congestion rents. However, this is at the expense of the wind farm operators at Kriegers Flak: prices in the offshore zone will always be lower than in the neighbouring highest-price zone [9]. In addition, congestion implies that deviations from scheduled generation cannot necessarily be balanced with the offshore wind park’s respective country. This can also lead to additional costs – on the wind farm operator’s side through additional balancing expenses as well as on the offshore grid operator’s side due to escaped congestion rents. Therefore, responsibilities and revenue streams might have to be reorganised in an offshore grid in comparison to the known conventional situation.
The obtained results depend, among other factors, on the assumptions on precipitation in the Scandinavian countries. In dry years, power prices are far higher in the Nordic countries and in such a case, prices decrease by additional interconnectors to the thermal-dominated central European power system. Another aspect is that from November 2011 onwards, Sweden will be separated into several price zones. This should be included in future calculations, but it seems reasonable to argue that the

Southern Swedish price will be more dominated by thermal power plants and thus, the price differential to central Europe would rather decrease.

6. Conclusion

This paper evaluates different topologies at Kriegers Flak for an offshore hub and their economic consequences with the WILMAR model. The main findings support the calculations provided by the feasibility study in central points. With support from the economic recovery package, investment can be judged positive under the conservative price assumptions taken here. This is especially valid for the largest option. As latest developments show a tendency towards choosing a smaller solution in the short run, further analyses should be done to generalise the above recommendation. Methodologically, they could include separating Sweden and Germany into several price zones and sensitivity analysis on Nordic hydropower inflow as well as on chosen fuel prices. Furthermore, an analysis of the daily planning process of offshore generation with a site-specific forecast error and day-ahead interconnector scheduling seems relevant.

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– Appendix IV –

Compressed air energy storage in offshore grids

Sascha T. Schröder, Fritz Crotogino, Sabine Donadei, Peter Meibom

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Compressed Air Energy Storage in Offshore Grids

Sascha T. Schröder[1], Fritz Crotogino[2], Sabine Donadei[2], Peter Meibom[3]

Abstract

Fluctuating renewable energy sources can be rendered more reliable by massive international grid extensions and by energy storages. The latter ones are partially discussed as offshore grids to combine the grid connection of offshore wind parks with international power trading. This paper gives a first assessment of offshore energy storage possibilities.

Compressed air energy storage (CAES) is a technology that has been used successfully onshore for decades and is the most economic large-scale storage option after pumped hydro. More efficient adiabatic CAES is under development. At the same time, the oil&gas offshore industry provides enough experience to state that a CAES power plant could be installed and operated offshore even though at considerable higher costs. Suitable salt formations for the salt caverns exist in and around the North Sea and to a lower extent the Baltic Sea.

Offshore energy storage can facilitate several issues in an offshore grid: firstly, it can delay or even replace the necessity for building interconnectors due to additional wind or wave power. Secondly, it can balance generation deviations due to forecast errors. Depending on market design, these have a negative effect on offshore generation or interconnector operation. Balancing forecast errors could allow operating the interconnectors in a more reliable and thus, more profitable way. If the offshore grid is considered a single price zone between countries, a storage has a lowering effect on electricity price volatility. The WILMAR planning tool is used to estimate these effects. Comparing onshore and offshore CAES, it is concluded that an an offshore adiabatic CAES can participate in several markets, but that this advantage is outweighed by an onshore unit's ability to provide spinning reserves.

1 Introduction

Achieving EU policy goals for renewable energy requires both a massive installation of renewable generation capacity as well as adjustments of the remaining infrastructure. The bulk of renewable generation such as wind and solar is fluctuating, so possible remedies comprise very flexible dispatchable units, flexible demand, large-scale extension of the transmission system and energy storage options. The focus of this analysis evolves around offshore wind energy in the North Sea. A strong meshed offshore grid would be able to balance power fluctuations partially. The largest share of power balancing could be either provided by strong interconnectors to the Norwegian-Swedish hydro-dominated system that could be operated as a pumped storage system. Alternatively, storage could take place closer to the Southern shore of the North Sea,

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where large amounts of offshore wind energy are to be installed – namely in Germany, Denmark and the Netherlands. These countries share the common characteristics that their coastal regions are flat, i.e. that pumped hydro cannot be realised regionally. Building new pumped hydro storages in Southern Germany faces environmental concerns as a central obstacle and requires new transmission capacity over several hundred kilometres. The only large-scale storage option that is currently operational in Northern Germany is a diabatic Cavern Air Energy Storage (CAES) plant. When electricity prices are low, air is compressed into an underground salt cavern. For generation, this pressurized air is injected into a gas turbine and thus, raises the turbine's efficiency. Adiabatic CAES, which is independent of gas supply and achieves a higher efficiency through a heat storage, has lately been the subject of a research project and is generally considered feasible (see also Crotogino/Donadei, 2011 or Gatzen, 2008). In several scenarios of a 100% renewable energy study for Germany, CAES plays a major role (German Advisory Council on the Environment, 2011). As technical feasibility is in principle also given for offshore locations, this paper analyses possible offshore applications. It is structured as following: first, technological issues are addressed. Second, economic effects in offshore grids are presented qualitatively before turning towards the model and data description. Onshore storage, offshore storage and an increased interconnector capacity between Germany and Norway are compared before moving to the discussion and conclusion of this first estimation on the subject.

2 Technology

2.1 Caverns

Natural gas has been stored successfully in large quantities in underground salt caverns for many years worldwide in facilities like the Ll.Torup Energinet Storage Facility in North Jutland, Denmark, see Fig. 1.

Salt caverns are artificially constructed cavities in salt deposits created by solution mining. Typical dimensions of salt caverns are a geometrical volume of 500 000 m³ at depths of over 1 000 m, and pressure ranges of 60 to 180 bar.

Unlike surface storages, salt caverns enable extremely large amounts to be stored at low specific costs. The storages are almost maintenance-free and they boast negligible leakage rates. This is why salt caverns are also highly suitable for the storage of compressed air and hydrogen.

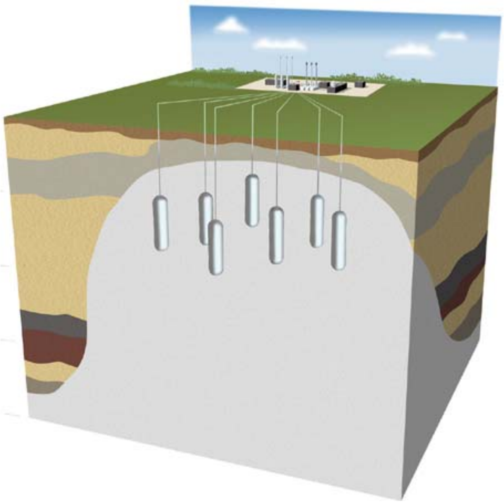

Figure 1: Figure 1: The 7 gas caverns in Ll. Torup (Energinet)

A precondition for the installation of salt caverns to store compressed air is the availability of suitable salt formations with the necessary thickness and the appropriate depth range of around 700 to 1 300 m. There also have to be adequate quantities of fresh water available for solution mining the caverns, as well as environmentally-compatible options for disposing of the large volumes of brine produced during the solution mining process.

A borehole with a cemented casing gives access to the cavern – an additional production string that can be pulled out of the cavern is also installed for safety reasons. In the special case of compressed air caverns, corrosion-resistance plays a major role because moist, salty compressed air is extremely corrosive.

The minimum and maximum pressures increase with the depth of the caverns. For instance, at the depth to the cavern roof of 1 000 m, pressures will be around 60 to 180 bar. This pressure range must match the operating pressures of the compressed air energy storage power plant. In the case of the CAES plant in Huntorf, Germany (the only CAES power plant in Europe) the air entering the turbine is at a pressure of 46 bar. This means that the depth of the cavern has to have matching specifications to enable the operating pressures of the storage and the turbine/compressors to be compatible.

The investment costs for salt caverns comprise a relatively high proportion for volume-independent costs for the solution mining equipment, infrastructure, pipelines, boreholes, and a volume-dependent share. Because the storage costs for a CAES power plant are typically only around 20% or less of the total costs, the actual storage volume which is realised plays only a minor role.

The interest in offshore caverns has risen in recent years for several reasons: a shortage of suitable onshore salt structures for natural gas caverns, and the ability of locating CAES-caverns next to offshore wind farms (Dena, 2011).

An example is the Gateway project involving the construction of around 30 caverns for natural gas storage in the Irish Sea off the coast of England. Figure 2 shows the whole facility in which each cavern is connected to a shared pipeline with an onshore compressor station. It also shows a monopod – a standpipe rammed into the seafloor – which acts as the platform for the equipment used to construct the cavern.

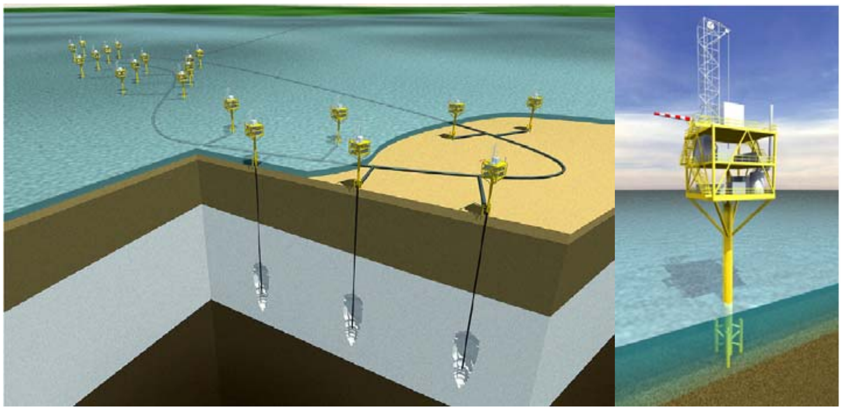

Figure 2: Planned offshore gas caverns in the Irish Sea (left), monopod for an offshore gas cavern (right). Stacey, 2008.

On the positive side is the easy access to adequate volumes of fresh water, and no problems with brine disposal. On the negative side are the much higher costs for well installations and maintenance work. The installation of power plants on offshore oil and gas platforms is state-of-the-art technology: the power plants are built in the port, pre-tested, and then towed out to their offshore locations. The feasibility of constructing an offshore CAES power plant is therefore less a question of the technology, and more a question of the considerable additional costs for installation, corrosion protection in the offshore climate, and maintenance.

2.2 Distribution of salt formations beneath the surface of North Germany and Denmark, and in nearshore parts of the North Sea

Rock salt is widely distributed beneath the surface of North Germany, Denmark, and the North Sea. It is found in beds ranging in thickness from several tens of metres to several hundred metres. The bedding of the salt formations ranges from nearly horizontal or slightly dipping packages, to undulating sequences, usually lying at depths of between two to five kilometres. They are overlain by younger sediments consisting of limestones, claystones and sandstones. The rock salt formed approx. 250 million years ago within the Zechstein Sea that covered large areas, including the Netherlands, the whole of North Germany, large parts of Denmark and of Poland and the area presently covered by the North Sea.

Because rock salt has a low specific gravity, geological changes over the course of geological time (including the development of faults) caused the salt to rise up towards the surface: this salt movement lifted up the overlying sediments as it formed a salt pillow. This process can proceed so far that the salt breaks through the overlying beds and pushes them to the side, giving rise to a salt diapir. These commonly have a mushroom-like shape, extending upwards for several kilometres in some cases. They have moved upwards to within a few hundred metres of the ground surface.

Up to 200 separate salt diapirs are known to exist in Northwest Germany. However, there are only a few isolated salt diapirs in Northeast Germany. Salt diapirs often have circular to oval horizontal cross sections with diameters of 5 to 10 km on average. The situation in the approx. 100 *130 km large area between Wilhelmshaven and W-Hamburg, as well as Flensburg and Kiel, is for three to five salt domes to be joined up to form several elongated salt walls with lengths of 50 to 100 km. Salt walls and numerous salt domes are also present in the southern, western and northern parts of the German sector of the North Sea.

The tops of the salt formations in the diapir salt structures in North Germany usually lie at depths below ground level of 400 to 1,200 m. The top salt in some salt domes or parts of salt walls can be deeper (>1,200 m) – especially in the central part of the German sector of the North Sea. On the other hand, there are salt structures with top salt at depths as shallow as 200 – 400 m along the North Sea coast of Schleswig-Holstein in particular, as well as near Bremen and Hamburg.

With the exception of North Jutland, the island of Fyn, and the area to the east of Sjælland, as well as a zone between Ringkøbing, Grindsted, Gram and Esbjerg, there are also salt deposits beneath Denmark. Salt formations have been confirmed underground beneath large parts of the Danish sector of the North Sea and the Baltic Sea. 14 salt diapirs have been located in an area covering around 90 * 120 km between Aalborg, Århus and Nissum Fjord. The maximum diameter of these salt diapirs is between approx. 4 and 11 km. Top salt in these structures usually lies at depths from approx. 200 to 500 m. To the north of Ringkøbing, there are 5 offshore salt diapirs at distances of 1 to 25 km from the coast, with depths to top salt of <500 m. Over 20 more salt domes have been identified beneath the Danish sector of the North Sea.

The uppermost parts of salt domes usually consist of anhydrite, gypsum and claystones forming the cap rock – with thicknesses of a few metres to >100 m. Experience has shown that the rock salt zones most suitable for the construction of underground salt caverns, i.e. those parts of the salt formation with the lowest concentrations of foreign lithologies (anhydrite, clay), lie in the central parts of salt domes.

Figure 3 and Figure 4 display the prevalence of salt structures in Denmark and Germany. For Germany, the offshore wind farms and their connection corridors illustrate that cavern storage would be possible in their proximity.

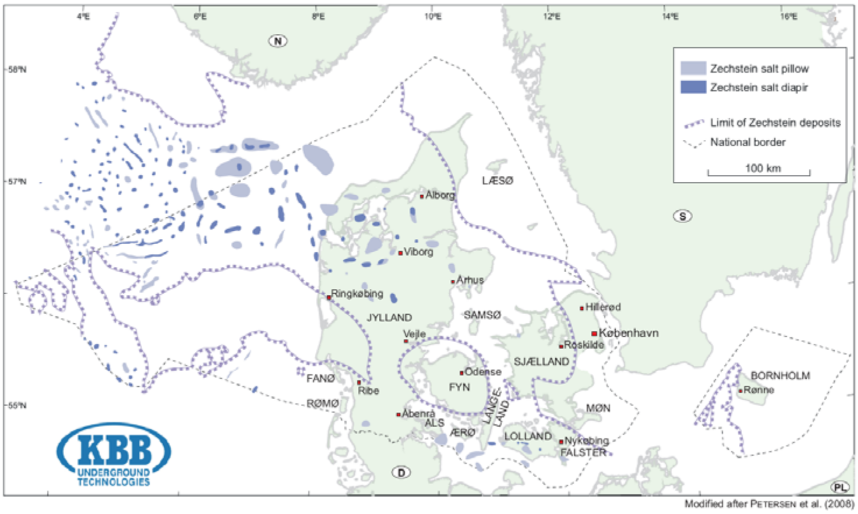

Figure 3: Distribution of salt deposits and salt structures in Denmark

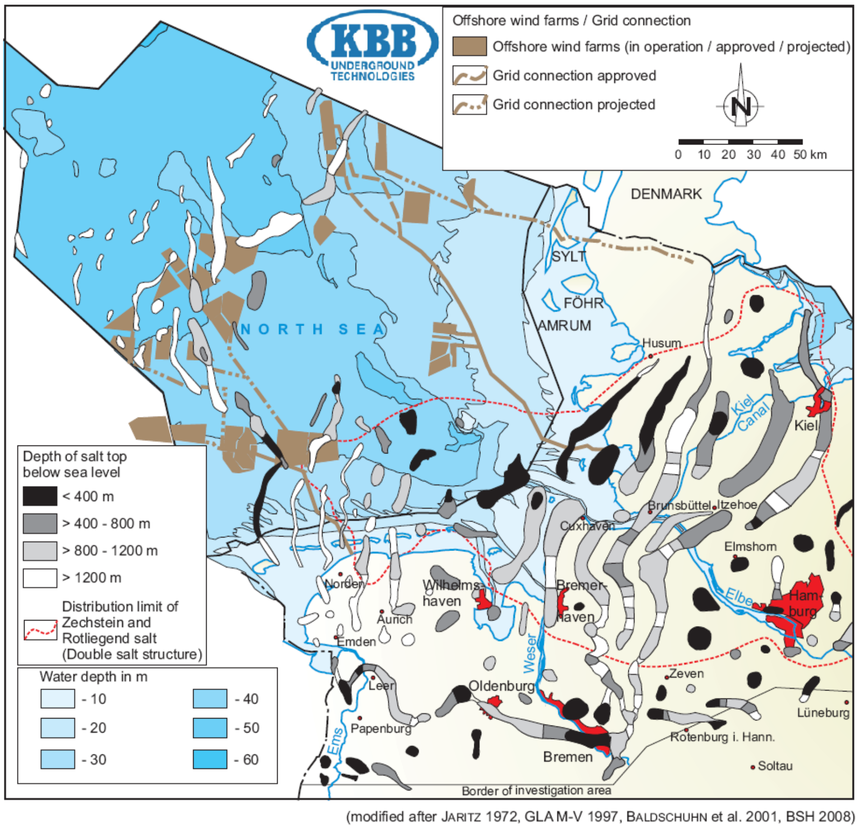

Figure 4: Salt diapirs in Northwest Germany and in the German exclusive economic zone of the North Sea

2.3 CAES and AA-CAES power plants

The two existing CAES power plants in McIntosh, Ohio, and Huntorf, Germany, have several decades of operational experience. As the adiabatic CAES (AA-CAES) technology is expected to reach a higher efficiency of 70% and does not rely on natural gas as an additional fuel, it is in the focus of this analysis.

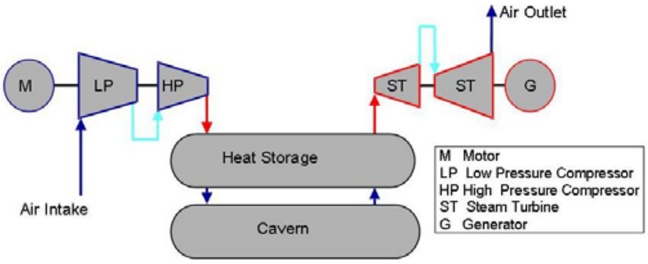

Figure 5: Function diagram of an adiabatic compressed air energy storage power plant in single-stage configuration (Zunft et al., 2006)

Figure 5 displays a diagram of the main components of an AA-CAES facility. The air is compressed and injected into the underground cavern while the heat is stored in the surface heat storage. When later producing power, the air passes through the heat storage again into an expander. Losses of the heat storage are estimated at 2% per day (Radgen et al., 2010). Note that a heat storage corresponding to 1,000 MWh has approximately a diameter of 20 m and a height of 30-40 m. This suits water depths in the North Sea of ca. 40 m, so that the heat storage could be used as a gravity foundation for the compressor and expander.

Radgen et al. (2010) assume that an onshore AA-CAES facility with a compressor of 150MW, 250MW, a storage capacity of 1,000MWh and a round trip efficiency of 70% requires an investment of approx. 180 Mill. Euro.

3 Offshore grids and economic considerations for storage

Offshore wind is a cornerstone of all North Sea riparian countries energy strategies. First offshore wind farms are mainly erected close to shore, but a large number will be built at large distances from shore. This requires HVDC connections and involves considerable connection costs. Several offshore wind farms can be connected via a single HVDC line, as is done e.g. for the German SylWin1 connection. For the future, a meshed offshore grid might provide a least-cost possibility of combining the connection of offshore wind farms to their countries and building interconnectors for international power trading. Figure 6 gives an illustrative example of a possible topology.

Economic considerations for investing in offshore storage technologies can be categorized as following. First, a storage can replace or deter the need for additional transmission lines. In the context of offshore wind energy, this seems most probably if changes to the original design of an offshore wind farm / cable combination take place – e.g. through the addition or upgrade of wind turbines leading to a larger installed capacity, or through the addition of wave power.

Second, a storage can increase reliability in the operation of a meshed offshore grid. Wind power generation is inherently associated with prediction errors, leading to the effect that power flows for international trading are scheduled suboptimally on day-ahead electricity markets. Local offshore energy storage could outbalance these prediction errors and thus, ensure a more reliable day-ahead scheduling of cables. The value of this option, however, depends largely on assumed rescheduling procedures.

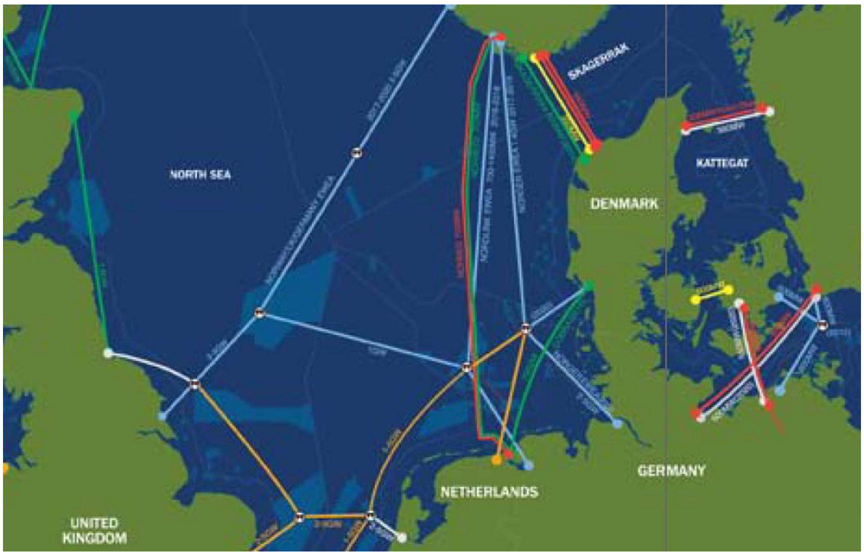

Figure 6: EWEA's 20 year Offshore Network Development Master Plan and Europe's offshore wind power development and concession zones [extract, EWEA (2009)]

The third point is of a more general nature: providing system reserves could be provided in a cheaper way by storages than by having additional fast-reacting thermal capacity installed. In a meshed offshore grid, however, these reserves can only be provided to a neighbouring country if the line towards the country is not fully utilised. In other words, an offshore storage will never be able to provide up-regulating reserves for the neighbouring country where demand is most scarce (reflected by high power prices and power import at the full capacity of the interconnector).

4 Model and data

The WILMAR planning tool (Wind Power Integration in Liberalised Electricity Markets) optimizes the operation of a power system with a focus on fluctuating wind energy. The time resolution is hourly, and the calculation period is up to a year. For wind power production forecasts, a perfect forecast without forecast error, a single forecast or several forecasts per region can be part of the optimization. The latter cases are based on the Scenario Tree Tool of the model, which calculates wind power production forecasts, load forecasts and demand for positive minute reserves as scenario trees. The Joint Market Model uses these data as input for the power system optimization. The geographical extension can be Europe-wide; for further details, see e.g. Barth et al. (2006), Tuohy et al. (2009) or Meibom et al. (2011). In this paper the model is run with a geographical scope covering the North Sea countries, namely Norway, Sweden, Denmark, Germany, the Netherlands, Belgium and the United Kingdom. Sweden is subdivided into 2 zones, whereas Germany is divided into 3 zones (Northwest, Northeast, Central-South) to represent bottlenecks due to transmission network constraints (Dena, 2011). The offshore hub in the North Sea is defined as a single country. Forecast errors are reflected deterministically, which is estimated to reflect current practice most appropriately. The assumptions for electricity demand, interconnector capacities etc. are largely in line with EWIS study assumptions for 2015, installed wind power is according to best estimate. Fuel prices are set at the comparatively high World Energy Outlook 2008 levels, with slight regional differences for transportation costs. An AA-CAES unit has in principle the same characteristics as pumped hydro, as Swider (2007) correctly points out. A major difference is that the compressor and generator could also be operated simultaneously.

Wind production at the offshore node in the North Sea is set at a nominal capacity of 1000MW with 5% unavailability. The wind power production has been generated from measurements at the FINO1 research platform at a height of 100m, following the multi-turbine power curve approach suggested by Nørgaard and Holttinen (2004). The annual course of data, which is used as input to the stochastic data model of WILMAR, is displayed in the following figure.

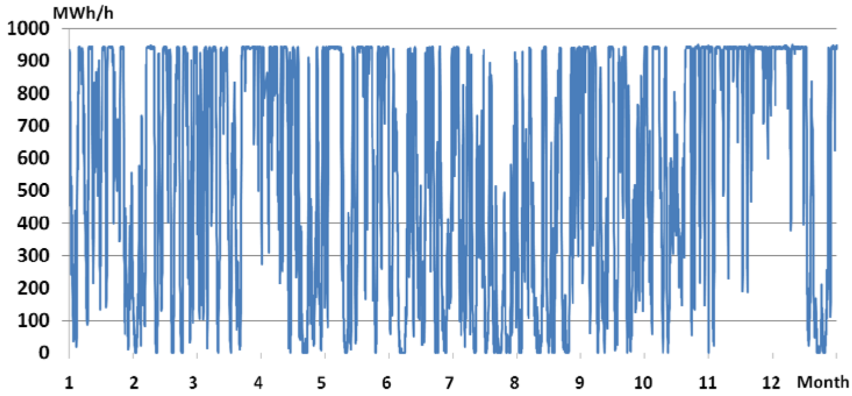

Figure 7: Wind power generation at the offshore site

5 Case descriptions

The underlying idea is to compare an onshore AA-CAES power plant e.g. in the Netherlands, Germany or Denmark with the option of placing it offshore. Alternatively, interconnector capacity to Norway could be increased. Three main exemplary cases are distinguished:

1. An AA-CAES storage (70% round-cycle efficiency) with a 150MW compressor, 250MW generator and a storage volume of 2,000 MWh is inserted in the Northwestern German electricity market region. Furthermore, an offshore hub with 1,000 MW wind power capacity and connected to the United Kingdom, the Netherlands and Northwestern Germany with an interconnector capacity of 1,000 MW each is added.

2. Everything else unchanged, the AA-CAES storage is placed in the offshore hub (instead of Germany).

3. The AA-CAES storage is replaced by an equivalently increased interconnector capacity (250 MW) between Germany and Norway.

6 Results

Figure 8 illustrates an example of storage operation at the offshore site. The value is indicated as net generation because these modes never occur simultaneously. It can clearly be seen that charging and production periods follow a diurnal pattern provoked by power prices.

Figure 9 shows the analogous example if the AA-CAES facility is placed onshore. Production does not reach the maximum capacity of 250 MW, and the compressor and generator always operate simultaneously. This is due to the fact that this operation mode allows the AA-CAES unit to provide least-cost spinning reserves to the overall electricity system. Spinning reserves are determined on a daily basis, which is why a daily spinning reserve level and hourly spikes caused by standard operation on day-ahead and intraday markets can be distinguished. It should be noted that positive spinning reserves can be provided by down-regulating the compressor as well as by up-regulating the generator (and vice versa). This leads to the effect that a least-cost solution is a case where the generator is permanently producing power with at least 30 MW. In conclusion, a large benefit of having the unit onshore is its ability to provide spinning reserves.

The storage capacity is only rarely used above 50% of its capacity (2,000 MWh). Thus, it seems reasonable that limiting the storage to 1,000 MWh capacity, equivalent to a single cavern, is beneficial.

As Figure 7 illustrates, there is a large number of successive hours when the wind power generation is close to its maximum. Therefore, dimensioning the cavern in a way that it would be able to absorb these long-lasting peaks and allow a smaller cable is not profitable.

Table 1 states the costs of offshore storage and additional interconnector capacity relative to the benchmark case (onshore storage). System costs are higher in case of an offshore location, which is partly due to the fact that spinning reserves need to be provided locally in Northern Germany. This is a competitive advantage for placing an AA-CAES facility onshore, though additional are possible by choosing an interconnector to the Nordic power system. This, however, cannot support covering the local demand for spinning reserves. In contrast to total system cost, CO_2 emissions are reduced by 0.01% if the storage is placed offshore or by 0.03% by an interconnection to Norway. With regard to AA-CAES, this is caused by the losses associated with operating the compressor and generator simultaneously for spinning reserves.

Table 1: Additional costs of different cases relative to onshore AA-CAES

		Offshore storage	Interconnector Germany-Norway
System cost	Mio. Euro	33.8	-73.0
CO2 cost	Mio. Euro	-2.4	-5.1
System cost	%	0.0464	-0.1003
CO2 cost	%	-0.0141	-0.0306

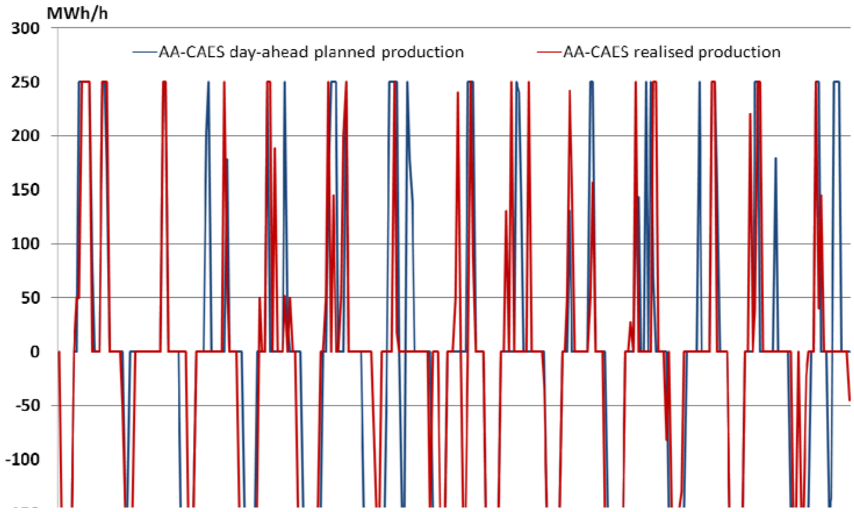

Figure 8: Storage generation at the offshore site (example covering days 2 to 14 of the year)

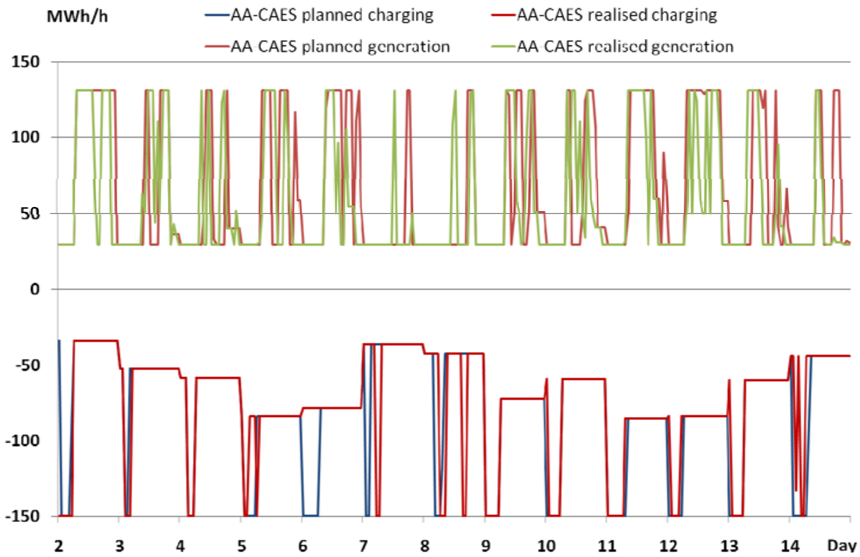

Figure 9: Storage generation at the onshore site (example covering days 2 to 14 of the year). Charging is indicated by negative numbers.

7 Discussion and conclusions

This paper compares an onshore AA-CAES with placing it offshore or an interconnector increase to a hydropower-dominated system. It concludes that placing an AA-CAES unit offshore is technically feasible, though at higher cost. The selected power price assumptions are comparatively high, which is generally beneficial for storage units. While the storage can interact with several intraday markets when it is placed offshore, this advantage is outweighed by the fact that it can provide spinning reserves onshore. The provision of spinning reserves through HVDC cables is a subject of ongoing discussions and therefore, the results might overestimate the benefit of the onshore siting. In every case, the onshore operation mode dominated by spinning reserves is remarkable and to the authors' knowledge the first time that this has been shown explicitly for an AA-CAES facility. Another aspect of having a storage unit onshore is that in scarce supply, both the import cable and the storage can contribute to covering local demand. If the storage is placed offshore, the total contribution is the import cable capacity (including storage generation). This is also an important conclusion for the idea of building integrated generation/hydro-storage units (PowerIslands) offshore.

For the future, it seems that AA-CAES is a promising technology that requires further research. Especially the round-trip efficiency of 70% needs to be validated. AA-CAES may prove valuable if international interconnections of several dozen gigawatts, as e.g. suggested by the German Advisory Council on the Environment (2011), cannot be built. However, onshore or nearshore locations in Germany, the Netherlands, the United Kingdom or Denmark seem more promising than far-offshore locations.

Public acceptance, locally scarce availability of geologic structures as well as environmental concerns and permission issues may be reasons for placing AA-CAES units nearshore, but in a way that they are not separated from their home country's electricity market by interconnector constraints.

8 Acknowledgements

The authors would like to thank the German Federal Maritime and Hydrographic Agency (BSH), the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) and Projektträger Jülich for their coordinated effort on publishing wind data from the FINO1 platform in the North Sea.

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– Appendix V –

Joint support and efficient offshore investment: market and transmission connection barriers and solutions

Sascha T. Schröder, Lena Kitzing, Henrik Klinge Jacobsen, Lise-Lotte Pade Hansen
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Joint Support and Efficient Offshore Investment: Market and Transmission Connection Barriers and Solutions

*Sascha Thorsten Schröder, Lena Kitzing, Henrik Klinge Jacobsen & Lise Lotte Pade Hansen**

Different support schemes are applied for the promotion of renewable energy sources in EU Member States. Current EU legislation opens opportunities for international cooperation to achieve national renewable targets more efficiently, either by statistical transfers, joint projects or joint support schemes. This article investigates their interplay with support schemes and applies the results to offshore wind energy. With all North Sea neighbouring countries planning offshore wind installations and considering a coordinated offshore grid, this constitutes a good starting point for coordinated action. Two case studies on the regulatory combinations of joint projects financed under tendering and tradable green certificates as a joint support scheme are contrasted, addressing main barriers and possible solutions. Joint projects are an interesting option in the mid-term, whereas joint support schemes may be more attractive on a longer time horizon.

I. Introduction

Offshore wind power plays a key role for the deployment of renewable energy sources in a number of countries, expressed through the existing National Renewable Action Plans (NREAPs). The key challenges for the industry are cost decreases, which are mainly going to be achieved with technological development – which is itself fostered by a specified policy framework. Namely, policy frameworks cover support schemes, connection regimes, and broader aspects such as marine spatial planning. The WINDSPEED project is the latest example of the latter field and covers the North Sea.[1] It extends earlier national approaches where possible areas for offshore wind power were designated and may play a role in increasing international collaboration in the future. This collaboration can consist of many different facets, such as joint support schemes or joint projects under the EU Directive 2009/28/EC[2] or the internationally coordinated connection of offshore wind farms. The possible benefits of coordinated support schemes with regard to offshore wind energy have lately been stressed again as a major point of action by the EU Commissioner Günter Oettinger.[3] Ropenus and Grenaa Jensen (2009)[4] provide an overview of collaboration benefits and risk characteristics of single support schemes. Roggenkamp

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1 Karina Veum, Lachlan Cameron, Daniel Huertas Hernando et al., *Roadmap to the deployment of offshore wind energy in the Central and Southern North Sea (2020–2030)*, WINDSPEED final project report, Amsterdam 2011.

2 European Parliament and Council Directive 2009/28/EC on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC. OJ L 140/16-62.

3 "Take the North Sea – it's not a British sea, it's not a German sea, it's not a sea of Denmark it's a European sea. We need integrated solutions for subsidies, for grids, for a common European North Sea grid and for a win-win-win effect in the interests of all consumers." – in: Sonja van Renssen, "Four instruments may be too much – interview with EU Energy Commissioner Günther Oettinger on renewable energy targets and emission trading", European Energy Review, 29 May 2012.

4 Stephanie Ropenus and Stine Grenaa Jensen, "Support Race against the European RES Target", presentation held at the 10th IAEE European Conference, Vienna, 2009.

et al. (2010)[5] are the first ones to illustrate a number of interesting connection constellations such as an offshore wind farm's connection to a grid different from its home country, or a wind farm being connected to several countries. Implementing such possibilities can be beneficial, as the OffshoreGrid project[6] indicates on a large scale. In addition, it highlights examples of benefits through combined connection of neighbouring wind farms and the incorporation of wind farms with transmission cables (e.g. the considered CobraCable connection between the Netherlands and Denmark, closely touching German offshore wind farms). However, implementing such internationally combined solutions leaves a number of regulatory challenges, such as incentives for the involved transmission system operators and offshore wind farm operators. If several neighbouring offshore wind farms with different national affiliations are to share transmission connections, a homogeneous policy framework may facilitate the solution of a number of issues: similar support scheme levels for one site are likely to be efficient, and useful connection responsibilities can facilitate the integration of the site's generation in an economic way.

This paper addresses a number of these issues: its starting point is the current EU legislation on national renewable targets as well as on support schemes. In the next section, implementation barriers are discussed before combining support scheme and cooperation mechanisms in a matrix and discussing their benefits and drawbacks. Based on this, we provide suggestions on how to overcome these barriers for two specific cases, namely for a tendering scheme for cross-border areas as well as for a tradable green certificate scheme for a larger geographic area. The subsequent discussions and conclusions section points out that close cooperation between involved EU Member States is necessary to benefit from expectable savings. Moreover, smaller solutions between single countries could expose the offshore supply chain to less risk than a solution involving multiple countries.

II. EU legislation

The current EU legislation on renewable energy is dominated by EU Directive 2009/28/EC.[7] For the first time, national targets for renewable energy have become binding. For each Member State of the European Union, a 2020 target for the share of renewable energy in final energy consumption has been set, so that the average Renewable Energy Sources (RES) share over all countries will be 20 % in 2020. Each country will have to achieve an increase of RES compared to the 2005 levels. The required increase is equally distributed over all countries, and adjusted by a few parameters, such as differences in income level. However, differences in the cost of electricity production from RES have not played a role in the target setting.

In some countries, though, RES projects might be significantly more costly than in others. It could therefore be beneficial for some countries to cooperate in reaching their respective national targets. This would reduce the overall compliance costs of the RES targets.

The EU Directive 2009/28/EC has opened up opportunities for joint compliance with the individual targets through the utilisation of so-called cooperation mechanisms. Between EU Member States, three cooperation options are defined:[8]

- **Statistical transfers** of RES production units from one country with "over-compliance" to a country undersupplied with RES production;
- **Joint projects** amongst EU Member States, with a contractual arrangement between the participating countries on how to allocate the RES production units of specified projects, in which both countries are involved; and
- **Joint support schemes** amongst EU Member States, with a jointly implemented support in both countries and a contractual arrangement on how to allocate the RES production units between themselves.

The details for the specific implementation of these mechanisms have not been laid out yet.

As part of the monitoring process demanded in Directive 2009/28/EC, each EU Member State has

5 Martha M. Roggenkamp, Ralph L. Hendriks, Bart C. Ummels and al, "Market and regulatory aspects of trans-national offshore electricity networks for wind power interconnection". 13 *Wind Energy* (2010), pp. 483 *et sqq.*

6 Jan de Decker and Paul Kreutzkamp (eds.), *Offshore Electricity Grid Infrastructure in Europe – a techno-economic assessment*, OffshoreGrid final project report, Brussels 2011.

7 EU Directive 2009/28/EC, *supra* note 2.

8 EU Directive 2009/28/EC, *supra* note 2, at pp. 30–32.

published its pathway on how to achieve its national RES target in the form of a National Renewable Energy Action Plan (NREAP). The plans were submitted between July 2010 and January 2011.[9] Currently, six EU Member States have integrated the use of cooperation mechanisms in their NREAPs on a quantitative basis. In total, the expected cross-border trade accounts for the very limited amount of only ca. 0.4 % of the expected EU renewables production in 2020.[10]

The theoretical potential for statistical transfers is large, but only in a perfect market where all governments act strictly economically rational, do not exhibit risk-avoiding behaviour, and have perfect foresight. In this case, those countries with future over-compliance could commit to statistical transfers sufficiently many years ahead. In practice, this might be for both the selling and the receiving party too risky of a strategy to follow cost-efficiently.[11] Therefore, it is expected that statistical transfers will be used more or less as an opportunistic measure to straighten out short and long positions of renewable energy production arising towards 2020, rather than as a strategic measure with significant trading volume.[12]

The mechanism of joint projects gives Member States the opportunity to develop projects outside their own borders if they enter into a project-specific or framework agreement with the Member State hosting the projects. An advantage of joint projects is that less expensive RES solutions can be pursued by one country outside of its borders without having to agree on a joint support with the hosting country and without joint changes in regulation. A disadvantage is the potentially high transaction and administrative cost of establishing this measure on a project-by-project basis.

Joint support schemes can be established between Member States that want to join forces in developing renewable energies. This joint support scheme could theoretically be designed for whole systems, a limited geographic area, or limited to specific technologies. A well-designed joint support scheme is expected to require a large preparation and implementation effort. Agreements for the allocation of the eligible RES production are required, as well as the establishment of a common support fund and the amendment of national regulations. Joint support schemes are on the other hand the most promising mechanism from a strategic cooperation perspective, since they can involve significantly more RES production than joint projects. The joint support schemes will also be significantly better rooted in both Member States' RES support and regulatory systems, which diminish uncertainty.

Joint support schemes have to be based on a jointly agreed policy type. The most commonly used RES support policies are Feed-in tariffs (FIT), which are guaranteed prices, Feed-in premiums (FIP), which are guaranteed add-ons to market prices, and quota obligations systems with Tradable Green Certificates (TGC). Mostly for technologies with typically large installation sizes, such as offshore wind parks, tendering processes are used to determine a cost-efficient, project-specific guaranteed feed-in tariff or comparable price premium scheme.

III. Barriers

EU Member States might engage in cooperating on joint support schemes if they all benefit from it. A mutually beneficial situation can be achieved if the overall benefits are greater than the overall costs, and if the costs and benefits can be distributed in a fair way. The challenge of designing such a fair distribution is probably the main barrier, but that is because one would have to deal with several effects arising from support schemes, power markets, and infrastructure investment. After an introductory overview of barriers, these specific barriers for support schemes and power market effects are addressed separately below.

9 Luuk W. M. Beurskens, Michiel Hekkenberg and Paul Vethman, *Renewable Energy Projections as Published in the National Renewable Energy Action Plans of the European Member States,* Energy research Centre of the Netherlands/European Environment Agency, 2011, at p. 30.

10 Own data analysis based on European Commission, National Renewable Energy Action Plans, submitted by EU Member States in line with EC Directive 2009/28/EC, available on the Internet at <http://ec.europa.eu/energy/renewables/transparency_platform/action_plan_en.htm> (last accessed at 18 November 2011).

11 Jaap C. Jansen, Ayla Uslu, Paul Lako. *What is the scope for the Dutch government to use the flexible mechanisms of the Renewables Directive cost-effectively? – A preliminary assessment,* Amsterdam: Energy research Centre of the Netherlands 2010, at p. 9.

12 See e.g. Corinna Klessmann, Patrick Lamers, Mario Ragwitz et al., "Design options for cooperation mechanisms under the new European renewable energy directive", 38 *Energy Policy* (2010). p. 4679 *et sqq.*, at p. 4684.

Klessmann describes the different elements of costs and benefits for each Member State under a cooperation mechanism:[13] The direct costs are the primary support cost for the produced RES electricity (i.e. Feed-in premiums). The direct benefit is the contribution to RES target compliance. There are also a number of indirect costs and benefits that must be addressed, such as: RES integration costs; the effect on power prices; conventional generator income; employment effects; and security of supply. Difficulties in quantifying these indirect costs and benefits may lead to certain barriers for the implementation of cooperation mechanisms. In some situations, the secondary benefits will fall entirely on the country expanding its RES capacity and this in effect could be hindering cooperation.

Local benefits (i.e. jobs, security, innovation, export options) are often mentioned as an especially significant element of renewable energy promotion by political decision makers, and they therefore form a barrier, if they will accrue only in one of the countries engaging in cooperation. The compensation for such indirect losses is very hard to quantify into a price premium on the RES-certificate transfer price.

1. Different support systems for Renewable Energy Sources

There are barriers related to differences in support system between countries, but just as important are the barriers resulting from different support levels. **Support system differences** cover combinations of feed-in tariffs, feed-in premiums, green certificates, or tendering auctions, as well as differences in the technology range, e.g. with technology banding or technology-specific support levels. **Support levels** create barriers as they are expressing the willingness of the respective population or government to pay for renewable expansion. Support for offshore wind has been granted at quite different levels in neighbouring countries around the North Sea. The result is that investors have been moving to the areas of highest expected revenues – these being derived mainly from the form of support. If two countries with different support levels considered implementing a joint support scheme, the investors in the market with the high support level would likely oppose a joint system, as this could result in lower overall support. Also, the power consumers from the low-support level country that have to finance more RES expansion at higher costs might be opposed to the joint system as well. The renewables industry, green development supporters, and renewable investors in the high support-level country would all oppose the reduction of support levels because cheaper options can be exploited and RES expansion in total would be at least the same.

2. Power market regulation, composition and price levels

Network regulation varies a great deal between Member States from the rate of return to incentive-based price and revenue caps. The details in incentive regulation include numerous differences and the enforcement of regulation is not always effective. Network regulation can assure incentives for networks to facilitate efficient connection of new technologies and network reinforcements.[14] If national regulation allows networks to include reinforcement investments caused by renewable generation in their capital base and revenue cap, this cost will indirectly be borne by network customers. In the case of a cooperation country receiving the RES credits, the project host country will require the receiving country to compensate it for these costs as well, although the transfer to network customers seems difficult to realise.

Power markets differ, even though they are in many cases coupled and, therefore, prices are correlated to some extent. Differences in market concentration and technology composition create some barriers. The mix of technologies in power generation can be more or less flexible to adjust to short term changes in renewable generation. It can be an important barrier for increasing the renewable capacity in a country if the inflexibility of the current generation capacity has an impact on the operation of additional RES capacity, possibly provoking curtailment in some instances. Price levels in some countries will not be affected very much from

13 Corinna Klessmann, "The evolution of flexibility mechanisms for achieving European renewable energy targets 2020 – ex-ante evaluation of the principle mechanisms", 37 *Energy Policy* (2009), p. 4966 *et sqq.*, at p. 4971

14 Stephanie Ropenus, Henrik Klinge Jacobsen, Sascha T. Schröder, "Network regulation and support schemes – How policy interactions affect the integration of distributed generation", 36 *Renewable Energy* (2011), p. 1949 *et sqq.*

increasing or decreasing the speed of renewable expansion. However, smaller countries, especially where renewable expansion potentials are abundant and cheap, could experience considerable changes in power prices and corresponding deterioration in profitability of existing conventional and renewable capacity. It is not necessarily easy to compensate the firms/producers that lose with the gain experienced by consumers in terms of lower prices. At the same time, the country facing the reduced prices will probably have to look for alternative ways of providing incentives for future investment in conventional capacity.

The *generation mix* might be quite substantially influenced by intensively exploiting one cheap renewable resource: first, by expanding the technology itself, and second, by the merit-order effect where zero marginal cost offshore wind energy pushes thermal units with higher marginal cost out of the supply curve.[15] This renders the least efficient base load plants less profitable or even loss-making. In the mid-term, the generation mix might then be affected in a direction that is providing less security of supply for power and makes the sector more vulnerable to change in the price of a few sources, or just one fuel price as with natural gas.

IV. Overview of regulatory combinations

The main benefits and disadvantages of regulatory combinations are displayed in Table 1. They are based on the following assumptions:

– Statistical transfers do not require a support integration of the participating countries because the transfer takes place at a higher institutional level, i.e. between countries. One of the main issues in this context is to choose the pricing mechanism for the transfer.[16]
– Joint projects refer to a narrowly defined offshore wind energy project in a specific geographic area. Participating countries, the support type and levels as well as the quantity target to be met are defined in advance.
– Joint support schemes are considered for a larger geographic area and, thus, potentially contain multiple projects. As with joint projects, participating countries, their current support schemes and levels as well as the quantity target to be met are defined in advance.

Regarding *statistical transfers*, they can be categorised as being parallel to national support schemes without affecting them directly. They could be agreed upon ex-ante or ex-post the construction of a respective excess RES capacity, where it is likely that the ex-ante solution would strive for a fair burden sharing and to sum the costs for additional capacity over the whole lifetime in the target year 2020. The ex-post solution distinguishes itself by the fact that one country erected excess capacity in comparison to its national target and the respective RES generation can be sold. As this is based on existing facts, the negation position of the seller depends on the non-compliance penalty: for a low penalty or the low likelihood of enforcement, the statistical transfer might happen at a lower rate than when including all related costs. For a penalty that is certain to be enforced and higher than the cost of additional capacity, the buying country may have to pay a higher rate than it could have procured ex-ante.

For *joint projects*, a common feed-in tariff or price premium can be attractive if the necessary support level is lower for at least one participating country. Inherent to this kind of policy scheme, the resulting generation quantity is unknown, implying that also the necessary amount of support cannot be predicted precisely. This does not constitute a problem for a tendering scheme: here, the quantity target is set and other conditions need to be defined narrowly. The resulting price depends on tendering conditions and competition to win the tender. In comparison to the feed-in tariff or price premium, this ensures achieving the project's quantity target to contribute to national RES targets, but the lower costs cannot be guaranteed from an ex-ante point of view. Combining Tradable Green Certificates with joint projects poses several challenges: an exclusive support scheme for joint projects would lead to low market liquidity and is therefore likely either to fail to meet the quantity target or to meet it at a comparatively high cost because market actors face an additional risk premium. If it is integrated into an existing Tradable Green Certificate system of the financing country,

15 Frank Sensfuß, Mario Ragwitz, Massimo Genoese, "The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany", 36 *Energy Policy* (2008), p. 3086 *et sqq.*

16 For an overview of different options, see e.g. Klessmann et al., "Design options for cooperation mechanisms", *supra* note 12.

<table>
<tr><th></th><th>Statistical transfers</th><th>Joint projects</th><th>Joint support scheme</th></tr>
<tr><td>Feed-in tariff, price premium</td><td rowspan="3">– Tool ‘above’ national support schemes
– Pricing / burden sharing
– Costs of total period represented in transfer for 2020 only
– Penalty for non-compliance</td><td>– Attractive if support level lower than the level of the country financing the project
– Resulting quantity unknown</td><td>– Attractive if joint support level lower than participating countries’ levels
– Resulting quantity unknown
– Geographical distribution of projects and related national affiliation uncertain in advance</td></tr>
<tr><td>Tendering</td><td>– Narrowly defined conditions
– Quantity target set, price results from competition</td><td>– Quantity target set, price results from competition
– Geographical distribution of projects and related national affiliation uncertain in advance (network connection difficult)</td></tr>
<tr><td>Tradable Green Certificates</td><td>– If specifically established for joint projects, then market liquidity too low
– If integrated into the existing system of the financing country, then market distortion problem</td><td>Quantity target set, price results from competition
– Geographical distribution of projects and related national affiliation uncertain in advance (network connection difficult)
– Steadily rising quota demand provides a reasonable market size for the industry</td></tr>
</table>

Table 1. Combinations of cooperation schemes and support schemes – main benefits and disadvantages

this could be distorted by the extension of offshore technology situated in a foreign country. For a small market, additional offshore resources that would join the quota market in a single year could affect the quota price considerably. However, from a qualitative point of view, this extension corresponds to other adjustments as changes in eligible technologies or technology banding rates that can be observed regularly.

The combination of feed-in tariffs or price premiums with joint support schemes shares some characteristics with joint projects. Due to the larger scope, the main additional issue is that the geographical distribution of projects and the resulting national affiliation are unknown in advance. This implies that cost and benefit calculations can only be agreed upon qualitatively and that a coordinated grid planning covering multiple offshore wind farms is hampered. This problem exists as well if tendering is applied, although it may be easier to achieve a specified quantity target. A Tradable Green Certificates scheme requires a large market size and increasing quantity targets to ensure market liquidity. If penalty rates for non-compliance are sufficiently high, this scheme can be expected to deliver the desired quantity at a lower cost than under single national approaches. However, the coordination difficulty with regard to connection planning and related cost and benefit distribution remains prevalent.

The main success criterion of international policy collaboration for meeting national RES targets is that a certain quantity is met. Offshore wind energy is today supported by tendering schemes (e.g. Denmark), feed-in tariffs (e.g. Germany), or quota mechanisms (e.g. United Kingdom). In addition, quota mechanisms seem the natural approach for internationally harmonised schemes with a focus on efficiency: Norway and Sweden are implementing a technology-neutral TGC scheme from 2012 onwards and a quota scheme (Guarantees of Origin) has for a long time dominated the discussion about a possible harmonised European support scheme. Based on these considerations, we choose to focus on two options that seem to have most practical relevance for our further analysis: a) a tendering solution for a joint project and b) a TGC scheme as a joint support scheme for a larger area. For both, we assume that they are technology-specific for offshore wind power and that the support is the only attainable support for offshore wind within the given geographic area. In other words, the combination of location and technology is exempt from applying to different national support schemes in order to avoid undesirable effects from overlapping schemes in the analysis.

V. Case studies

Based on the considerations discussed above, we have investigated two specific cases, one on joint projects involving a tendering scheme, and a second one on a joint support scheme involving a quota obligation with tradable green certificates specifically established for the defined area.

1. Case A: Joint projects – tendering for specific locations

The main properties of this case are that two countries engage in a common project at a narrowly defined location. A specific amount of wind energy is to be installed in this location and a tendering mechanism is chosen as the support scheme. The tendering design follows the Danish design: the contract is awarded to the bidder requiring the lowest support level, a guaranteed price per MWh. However, this is not a simple feed-in tariff where daily operations are administered by a third party, but a variable price premium filling the gap between the average power market price over a period of 3 months and the awarded tendering price level. For everyday operations, the offshore wind farm operator is himself responsible of forecasting and selling the generation as well as managing imbalances. We assume furthermore that the joint project is physically connected to only one of the contract states in a first step. Thus, the other contract state participates only via the support mechanism. Figure 1 illustrates the joint project solution between two countries in comparison with a standard national solution.

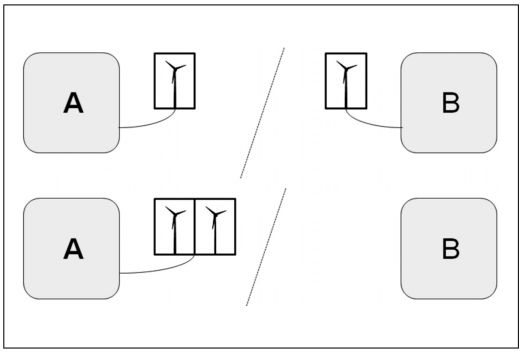

Figure 1. Standard national solution (upper part) and possible outcome under a joint project (lower part)

For the country supporting cheaper RES generation sited abroad, the expectable benefits due to a better wind site with possibly shallower water and closer to shore are quite straightforward. The opportunity cost of building an inland project is the main benchmark indicator. For the country to which the connection is established, the following cost and benefit elements are relevant and may be subject to the intergovernmental project contract:

- an increase in interconnection investment;
- an increase in national grid reinforcement costs;
- increased reserves costs;
- the merit-order-effect lowering power prices; and
- site blocking for possible future extensions/meeting future national targets.

In addition, the share of additional benefits as employment effects and local industry support during construction as well as operation and maintenance of the offshore wind farm may change between countries due to the different siting. Another aspect that has not been highlighted above is the risk of transmission failures over longer time periods. Regarding this, the regulatory incentives of the connecting country become crucial. It needs to be agreed whether this risk of transmission failure is to be shared among countries or whether the transmission operator has to compensate the offshore wind farm as well as the involved countries for foregone benefits.

It is inherent to the system that making sites available for third-country access blocks these sites from later national development. In other words, if binding targets are agreed on, e.g. for 2030, the most favourable locations will be blocked already. This risk aspect may also be reflected in the contractual agreement between countries, defining who keeps the right in RES generation to meet possible future targets beyond 2020.

The OffshoreGrid project[17] has shown that combined connection solutions are beneficial even if one of the wind farms gets delayed by several years. We estimate that the increase in offshore connection cable investment can be quantified fairly easily, but that building larger transmission connections due to the possible later connection of additional wind farms (for joint projects) may be difficult to negotiate due to sunk-cost characteris-

17 De Decker and Kreutzkamp, *supra* note 6.

tics. In contrast to that, the increase in national grid reinforcement costs and increased reserve procurement costs as well as the merit-order effect are harder, if not impossible, to quantify. The difficulty with regard to the merit-order effect arises from its ex-post character: in a stable system, it can be assessed from an ex-post point of view. However, taking investments over a longer period into account, the extension of RES generation has an effect on the composition of the power plant portfolio and alters the merit-order curve.[18]

Finally, an important aspect that has not been covered in the literature until now is the security of supply property for a certain price level that is inherent to tendering/FIT mechanisms: if parts of the national power generation have a guaranteed income level, then customers are also partially unburdened from fossil fuel price fluctuations. When tendering a wind park based on a guaranteed income level composed of the market price and the premium, the customers pay this fixed level. If power market prices rise, the premium is reduced accordingly and vice versa. This provides security of supply benefits to customers: the wind park's share of electricity generation in the national generation portfolio comes at a fixed price. Under the novel situation of tendering a wind park connected to another country, this characteristic trait of the support scheme is lost. Fossil fuel prices in both countries correlate, but depending on the countries' generation structures, they are more or less exposed to these fluctuations. Let us assume that a country has a high dependency on fossil fuels and both fuel and electricity prices rise. The country supports an extraterritorial wind farm under a guaranteed price support scheme. The wind farm is connected to a country that is less exposed to the price increases, which is why the premium stays relatively high. Thus, the country's electricity consumers are subject to both the higher power prices and the high support. Of course, this mechanism can also work inversely.

2. Case B: Joint Support Schemes – Tradable Green Certificates for a larger area

Figure 2 displays the possible outcome under a TGC scheme between the countries A-D. In this example, resulting offshore wind farms are only built in

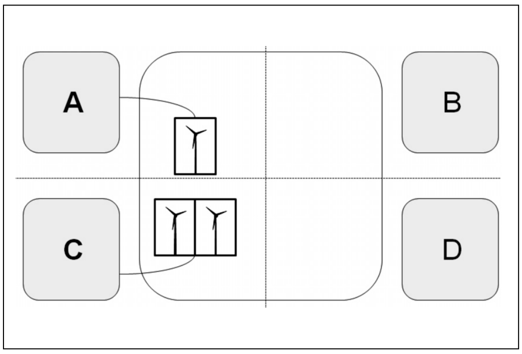

Figure 2. Possible setup in an offshore-TGC scheme of four countries

the sectors of the countries A and C. The idea of a TGC scheme between several countries has been addressed e.g. in Grenaa Jensen and Morthorst (2007).[19] Their main points are that in comparison to national schemes, distortions in the conventional power sector can lead to higher CO_2 emissions. In addition, it can be expected that a common TGC market works best if other market structures, such as the power market, are already integrated. This condition is fulfilled for the Swedish-Norwegian market to be established from 2012 onwards.

Regarding the case put forward here, two crucial differences are that firstly, a *technology-specific* TGC scheme is the focus of the discussion. Secondly, countries with neighbouring offshore areas do not necessarily share onshore borders as well, which is a traditional prerequisite for integrated power markets. Existing offshore high voltage direct current (HVDC) connections have a rather low capacity in relation to total market sizes. Permission procedures and other administrative burdens do not have to be identical between countries, but they should have similar procedures and time horizons to ensure that they do not negatively affect investment decisions.

It is an obvious benefit that offshore wind parks are a large-scale technology with professional participants only. Transaction costs can be expected to

18 Ralf Wissen and Marco Nicolosi, *Comments on the current discussion about the merit-order effect of renewable energy sources (Anmerkungen zur aktuellen Diskussion zum Merit-Order Effekt der erneuerbaren Energien)*. EWI Working Paper 03/7, University of Cologne.

19 Stine Grenaa Jensen and Poul Erik Morthorst, *Co-ordination of Renewable Energy Support Schemes in the EU*, Roskilde: Risø International Energy Conference, 2007.

be low for this reason. However, market liquidity may be an issue during the start phase of such a support scheme. Furthermore, the erection of offshore wind parks and respective transmission lines has some bulk characteristics. This feature is not fully compatible with increasing the quota demand steadily. A centrally coordinated approach allows harvesting gains from combined transmission connection that account for a considerable share of total cost.[20] A quota banking permission may help to partially overcome the bulk characteristics, but not the siting/transmission coordination issue.

VI. Discussion and conclusions

Support policies that utilise cooperation potentials and involve the integration of several countries would lead to a more efficient deployment, i.e. use of the best wind resources first. In other words, a stronger clustering than under the current national approach can be expected. This benefit should be put into perspective relative to the possible benefits of large-scale spatial levelling: a comparatively even geographic distribution of fluctuating generation leads to less total output variations than a local clustering. A number of the presented considerations will gain more relevance if post-2020 renewable energy goals are agreed upon because the choice of far-offshore locations by several countries can lead to more opportunities for collaboration. Accordingly, ensuring the flow of the offshore wind power towards the country with the highest power prices may be more decisive than low transmission investment costs. When establishing joint projects or joint support schemes, it should be encouraged to consider alternative connection options other than the default national affiliation of the offshore sector. An intergovernmental agreement seems an ideal opportunity to foster the least-cost connection into planned interconnectors and/or to high-price markets. Joint mechanisms require a political agreement where price or quantity targets are set. In order to increase planning and investment security, it is important that the agreed prices and quantities constitute firm commitments with liabilities for all participating countries. It would be devastating for the cooperation between the countries and therewith the overall wind deployment if political changes in one country could unilaterally affect the functioning of the joint mechanism. We advocate therefore binding international contracts without unilateral opt-out clauses. Changes and renegotiations of the joint mechanism should always be a matter of unanimous decisions by all participating parties. Even national measures that could possibly effect the functioning of the joint mechanism, such as connection charges, should be subject to agreement between participating parties, especially whenever changes are considered. Under both of the cases discussed in this paper, it seems beneficial if governmental bodies are in charge of marine spatial planning and the first steps of site assessments, e.g. with regard to environmental constraints. This ensures that only a smaller number of sites are considered; this would help constrain infrastructure costs. Here, the two regarded combinations exhibit different characteristics: for the tendering mechanism, the necessary grid connection can be planned quite precisely and the generation from the joint project could be estimated reliably also as a part of a larger infrastructure, e.g. an offshore grid. Under a tradable green certificate scheme, however, neither the locations nor the timing of expectable installations are known. This can be expected to increase infrastructure cost considerably.

In conclusion, the new cooperation schemes facilitate a more efficient attainment of EU RES targets for 2020. Statistical transfers are the option that requires least coordination between national policy schemes but at the same time being the option that offers the least security for RES development and hence compliance. By contrast, the analysed technology-specific cases of a) tendering mechanism for a joint project and b) quota mechanism as a joint support scheme call for a firmer and more detailed integration of national approaches. Both have the potential to be beneficial, especially if the criteria above outlined are followed. In the comparatively short time until 2020, it seems more realistic to coordinate joint projects based on tendering than to set up a quota scheme. The latter may however become a more relevant long-term option if post-2020 targets are defined.

20 De Decker and Kreutzkamp, *supra* note 6.

– Appendix VI –

Regulating future offshore grids: economic impact analysis on wind parks and transmission system operators

Lena Kitzing, Sascha T. Schröder

Proceedings of the European IAEE 2012 Conference, Venice
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Lena Kitzing and Sascha T. Schröder

REGULATING FUTURE OFFSHORE GRIDS: ECONOMIC IMPACT ANALYSIS ON WIND PARKS AND TRANSMISSION SYSTEM OPERATORS

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Abstract

The increasing development of offshore wind parks in the European offshore territory may lead to meshed offshore grids in which each wind park might be connected to several countries. Such offshore grids could be subject to various regulatory regimes, depending on the degree of cooperation between the respective countries. This study focuses on how investors in wind parks and transmission systems are affected by the choice of regulatory regime in offshore grids with one to four countries connected. In order to capture the uncertainties related to the exposure to market prices as well as risks related to line failures, we develop a stochastic model for an exemplary wind park and offshore grid. This yields the real option values of operational flexibility from additional connections. Simulation results show that the choice of regulatory regime, including market access and pricing rules, can have a significant impact on the value of a wind park and on the value of the interconnection capacity in the offshore grid. The impact can both be positive and negative, implying a complex incentive structure for the involved actors. If contrary effects are not reflected in the remuneration level of a wind park, for example in the price premium level, investment incentives could either be diminished or the wind park could incur windfall profits. Both cases are socio-economically suboptimal as they may pose additional cost to the system. Policy makers should consider these findings when designing the regulatory regime and level of support in an offshore grid in order to maintain an effective and efficient development of offshore wind in Europe.

Keywords
Economic impact analysis; Offshore grids; Offshore wind; Regulatory regime

1 Introduction

Offshore wind energy is one of the cornerstones for achieving a higher share of renewable energy sources (RES) in a number of coastal European countries. Until now, the connection of offshore wind parks is mainly pursued from a national approach. However, with the increasing number of offshore wind parks in the European offshore territory, the interconnection of offshore wind parks in meshed offshore grids with simultaneous connection to more than one country is coming more and more into focus. An early example is the Kriegers Flak project in the Baltic Sea where Denmark, Germany and possibly Sweden at a later stage collaborate on a common offshore node. Similar projects are also under discussion for the Irish Sea and for the North Sea. A study on the latter demonstrated that a common connection of offshore wind parks as well as further connections between them can lead to large cost savings and extra benefits from

electricity transmission of up to 21 billion Euro for the North Sea region (deDecker and Kreutzkamp, 2011).
An offshore grid would enable a joint system optimisation across wind parks, interconnections and electricity markets. This is expected to be of socio-economic benefit, amongst others thanks to infrastructure cost reductions, increase in security of supply for all participating countries, enhancement of trade between markets, and benefits from an improved market integration of the fluctuating wind energy (deDecker and Kreutzkamp, 2011).

Offshore grids could be subject to various regulatory regimes, depending on the preferences as well as the degree of cooperation between the participating countries. More specifically, the countries would have to agree on the regulation of market access for the interconnected offshore wind parks and would have to design the pricing rules. Also the level of cooperation regarding renewable support and in some cases the choice of support scheme for the offshore area are to be considered.

Research in the field of offshore grids for wind energy is increasing: beside the aforementioned study by deDecker and Kreutzkamp (2011), research is undertaken on technical level, e.g. by Trötscher and Korpås (2011) regarding an optimal topology of an offshore network, as well as on regulatory level, where Roggenkamp et al. (2010) analyse offshore electricity grids and their potential implementation in respect to market and regulatory aspects. Woolley et al. (2012) analyse legal aspects of offshore grids, including the cases where an offshore wind park is in addition to its 'home' country also connected to one other, and where it forms part of a meshed offshore grid. Schröder (2012) shows that participation in national balancing markets constitutes a main part of the economic attractiveness of an offshore wind park and that an interconnection to several markets will impact the business case.

Most of these analyses deal with offshore grids from a macroscopic perspective. There is however a certain lack of understanding as of how the market actors, especially the investors in offshore wind parks and transmission systems, are affected by the choice of regulatory regime in an offshore grid. This understanding is of utmost importance when designing the regulatory regime in order to ensure adequate investment incentives for wind parks and transmission capacity. A step towards this understanding was taken in an earlier study by the authors (Schröder and Kitzing, 2012) and is further elaborated in this paper. We approach the research gap with a real-options approach: we investigate an offshore wind park in an offshore grid under different regulatory regimes and support scheme constellations, and determine the option value of operational flexibility for additional interconnections. With the further development and extension of the quantitative model, we now address the economic impact of different regulatory regimes on the investors and operators of wind parks as well as transmission systems.

Our model shows that there can be both positive and negative effects on the business case of the offshore wind park operator. We argue that the specific effects should be considered when choosing the regulatory regime and designing the support scheme in the offshore grid, in order to maintain the effective and efficient development of offshore wind in Europe.

The remainder of the paper is structured as follows: after an explanation of the investigated cases in section 2, we address the applied method in section 3. Then we turn to the quantitative results and their discussion (sections 4 and 5). The paper concludes with qualitative conclusions and considerations on policy options (section 6).

2 Possible regulatory solutions and pricing schemes in offshore grids

We investigate a fictive offshore wind park in an offshore grid, connected to between one to four archetypical European markets, with regard to different regulatory regimes and support scheme constellations. We consider two different support schemes: Feed-in tariffs and price premium mechanisms. Under Feed-in tariffs (FIT), a fixed remuneration per MWh is guaranteed and paid to the wind park operator for a fixed number of years (or generation hours). Selling the generation on power markets and correction of forecast errors is typically administered by the TSO, leaving the wind park operator with only limited market risk. Price premium mechanisms, or Feed-in premiums (FIP), are typically fixed add-on payments to the market price. The wind park operator has to sell the generated electricity on power markets and is exposed to both market price risk and forecast errors.

Since wind farm operators under feed-in tariffs are not exposed to significant market risk, market pricing rules do not play a decisive role in the investment decision. In the case of feed-in premium mechanisms, operators are exposed to market price signals and market pricing rules for the offshore grid become decisive. In extension to our previous analysis, we distinguish three fundamentally different regulatory regimes in terms of market access and spot market pricing rules:

1) **'Home' country**: The wind park in the offshore area is assigned to one 'home' country and has only secondary access to the other connected markets;
2) **'Primary access':** the offshore area is flexibly integrated into any of the neighbouring markets, so that the wind park operator has access to the respective maximum price;
3) **'Offshore hub'**: the offshore area forms its own market price area and thus the wind park operator is subject to specific nodal pricing.

The first case depicts a situation of limited cross-country coordination, when for example the participating countries would like to benefit from the price-equalising effects of additional interconnection capacity between the markets, but are not cooperating at a higher level, such as regarding the support scheme. Then, an offshore wind farm would be assigned one 'home' country into which it would primarily sell the power and receive the support. In case the market price in another country happens to be higher than the one of the 'home' country plus support, the wind park may choose to sell the power in that market. This is socio-economically not an optimal utilisation of the interconnection capacity as the price-equalising effect will be distorted by the support level. This effect is reflected by lower congestion rents collected by the transmission system operators (TSO).

The second and the third cases do allow an optimal utilisation of the interconnection capacity, as we here assume a support scheme specific for the offshore area, i.e. the wind park would receive a price premium no matter in which market the power is sold. The two cases differ in the pricing rules: In the second case, the production from the wind park is integrated in one of the neighbouring markets, and will receive the price of the respective market. The choice into which market to sell is left to the wind park operator. He will directly sell the produced power into any of the markets via a specifically reserved capacity in the interconnectors. The rest of the interconnectors are dispatched in implicit auctions. We refer to this case as the ‘primary access’ case.

In the third case, the offshore grid becomes an integral part of a larger market area with different price nodes (such as the Nord pool area), with implicit auctions on the entire interconnection capacities, and a separate price that may form in the offshore grid node in case of congestions. The offshore wind park operator will always be subject to the price that forms in the offshore node, which in many cases is equal to the lowest or a medium price of the neighbouring markets (Schröder and Sundahl, 2011). We refer to this case as the ‘offshore hub’ case with nodal pricing.

The number of countries (and therewith markets) that are participating in the offshore hub with respective interconnector capacities are decisive for the attractiveness of investment in an offshore wind park. In the benchmark case, only a connection to one market is assumed. We investigate the economic impact on the business cases for the wind park and interconnection cables induced by additional connections to other markets under all three regulatory regimes. Figure 1 illustrates the different fictive connection situations distinguished in this paper: the benchmark case is a 600 MW offshore wind park connected to country A by a cable with the same capacity. This connection can be complemented by additional 600 MW interconnectors to the neighbouring countries B, C and D.

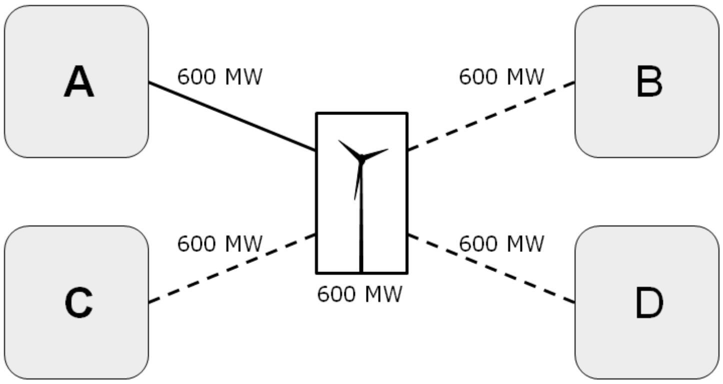

Figure 1: Overview of connection options in the considered cases

In addition to the connections, two other parameters are worth investigating: failure risk of any of the connections might impact the business cases significantly, depending on the regulatory set-up. Especially relevant for the stochastic analysis and therewith the option value is the strength of price correlation between the investigated markets.

The above considerations lead us to the following cases we investigate during the remainder of the paper:

	Benchmark	'Home' country case	Primary access case	Offshore hub case	Special cases
Geographical area	Country A	Countries A + B, C, D			
Renewable Support	Feed-in tariff Feed in Premium	Feed-in Premium (in Country A)	Feed-in Premium (joint scheme)		
Applicable price areas	Country A	Country A, and very high prices in countries B to D	Highest prices of countries A to D	Offshore price node (typically median of prices in countries A to D)	
Special events	-				Line Failures High market correlations

Table 1: Overview of the analysed cases and their main distinguishing characteristics

In order to capture the uncertainties related to the exposure of the offshore wind park to market price fluctuations under a price premium scheme and to integrate line failures into our considerations, a stochastic model is applied for the quantitative analysis. We use a real-options approach where any additional value related to the operational flexibility of being connected to other countries is regarded as the option value of the additional interconnection.

3 Method

Market prices of the different markets are modelled as stochastic mean reverting Wiener processes, following well-established methods. Stochastic line failures with are reflected by the authors' own approach, inspired by previous modelling of jump processes in commodity prices (see e.g. Hambly et al., 2009). We then compare the mean expected value of a wind park and its standard deviation in the different cases of regulatory regimes and country-connections to the benchmark case. This benchmark case is a wind park connected to one country only. At the same time, changes in congestion rents obtained by the involved TSOs for the different cases are analysed.

3.1 A stochastic model for the value of a wind park under price uncertainty

We use a well-established and often used approach (based on Dixit and Pindyck, 1994) to develop a stochastic model of the spot electricity price in four countries, where electricity prices are a stochastic process following a Brownian motion. The stochastic behaviour of prices, including drift and volatility, are exogenously given to the model. It has often been shown that most commodities in general and electricity prices specifically show characteristics of mean reversion and seasonal patterns (Lucia and Schwartz, 2002). Considering the nature of the analysis, which is a comparison of different cases with the same underlying market price processes, we include mean reversion in the model, as it will indeed affect the results, especially because the cases are sensitive to small price differences between the countries. Seasonal patterns however are not expected to modify the comparative attractiveness of the cases significantly, as they would apply similarly to all countries. Therefore, seasonal patterns are not included in the model. The price processes are modelled as plain mean reverting Wiener processes after Dixit and Pindyck (1994). The stochastic change of price in each time step dx is expressed with the mean reverting stochastic process:

$$dx = \kappa * (x^* - x)\, dt + \sigma\, dW_t \qquad (1)$$

Where:

W_t is a Wiener process with independent increments at

$W_t - W_s \sim N(0; t-s),\ for\ 0 \leq s < t$

κ is the mean reversion factor of the market (exogenously given)

σ is the standard deviation of the market (exogenously given)

x^* is the 'normal' level of the price x_t, to which it tends to revert, i.e. the long-run marginal cost of production in an electricity system

The processes are Markovian, meaning that the distribution of future prices is only dependent on the present price and not the past history of prices, i.e. it follows fundamental signals. In this framework, the price x_t in each time step can be calculated from the previous price plus the expected change dx from a stochastic process:

$$x_t = x_{t-1} + dx \tag{2}$$

For the simulation, we use the related first-order autoregressive process in discrete time (see Dixit and Pindyck, 1994, p. 76):

$$x_t = \overline{x_t} * (1 - e^{-\kappa}) + (e^{-\kappa} - 1) * x_{t-1} + \varepsilon_t + x_{t-1} \tag{3}$$

Where:

$\overline{x_t}$ is the 'normal' level of x_t, to which it tends to revert. $\overline{x_t}$ includes a drift in the process and is therewith also dependent on t

ε_t is a normally distributed random variable with mean of zero and variance of

$$\sigma_\varepsilon^2 = \frac{\sigma^2}{2*\kappa} * (1 - e^{-2\kappa}) \tag{4}$$

Having the stochastic price processes for all four countries in place, we then model the hourly expected future cashflows of the wind park mainly dependent on revenues from sales into the different spot market based on the restrictions given by the different cases we investigate. Next, future cashflows are aggregated over the analysis period, i.e. the lifetime of the wind project, and add a traditional discounted cashflow calculation to determine the project value, here expressed as the internal rate of return in each scenario and each realisation of the stochastic price process (Brealey and Myers, 2002).

$$NPV = \sum_{t=0}^{T} \frac{CF_t}{(1 + IRR)^t} = 0 \tag{5}$$

Where:

IRR is the internal rate of return in each realisation of the price processes in each scenario

NPV is the net present value of the wind park

CF_t is net cashflow in period t (net of positive and negative cashflows)

t is the time period of the Cashflow

T is Number of periods, i.e. the lifetime of the wind park

Mean and standard deviation of the net present value of the project for the different cases are determined by a Monte Carlo simulation (N=1000) capturing different realisations of the price processes.

3.2 A model for stochastic line failures

Stochastic line failures are added as an optional choice to the model. We model the probability of occurrence of a line failure with a Poisson distribution $P(\lambda)$, which reflects the nature of the failures much better than e.g. a normal distribution. This modelling approach is comparable to modelling of jump processes in commodity prices (see for example Hambly et al., 2009). The probability of duration of the line failure is modelled as a normal distribution $N(0; d)$. We also add an exponential recovery process for the available capacity y_t when ramping up after the line failure, approaching exponentially to the maximum available capacity $\hat{y}$, the nominal capacity of the interconnection capacity between the wind park and the respective country.

$$y_t = \hat{y} - \hat{y} * i_{(t,\varepsilon)} - \left(\hat{y} * j_{(t,\theta)} + (e^{-\kappa} - 1) * y_{t-1} + y_{t-1}\right) \quad (6)$$

Where:

y_t is the value of available interconnection capacity, being restricted to $0 \le y_t \le \hat{y}$

$\hat{y}$ is the nominal capacity, i.e. the maximum available interconnection capacity between the wind park and the respective country. It also serves here as the jump size in the Poisson process, meaning that the failure is expected to affect 100% of the capacity

κ is the recovery rate of the exponential process towards the maximum available capacity $\hat{y}$

$i_{(t,\varepsilon)}$ is the variable that activates the line failure, with

$$i_{(t,\varepsilon)} = \begin{cases} 1, & \varepsilon_t > 0 \\ 0, & \varepsilon_t = 0 \end{cases}$$

ε_t is a Poisson distributed random variable with mean of λ , $\varepsilon_t \sim Pois(\lambda)$

λ is reflecting the expected number of line failures per year

$j_{(t,\theta)}$ is the variable that activates the recovery process after an outage, with

$$j_{(t,\theta)} = \begin{cases} 1, & t = t_p + \theta_t \\ 0, & t \neq t_p + \theta_t \end{cases}$$

t_p is the maximum value of t, in which a line failure last occurred, with $t_p = t \ at \ \varepsilon_t > 0$

θ_t is a normally distributed random variable with mean of zero and standard deviation of d, $\theta_t \sim N(0; d)$

d is reflecting the expected number of hours the outage lasts

3.3 Assumptions

As described in a previous section, we investigate a fictive case with four archetypical markets and a typically sized offshore wind farm of 600 MW. We assume the addition of 600 MW interconnectors to other countries as main distinction criterion between the cases. This has a crucial effect on results: the capacity of the wind farm is such that typically all its power can be sold into one market. Other capacity combinations, especially combined with different electricity price characteristics in the neighbouring countries, would most likely have a considerable impact on the results. This issue is dealt with in a sensitivity calculation, where we vary the connection capacity.

The electricity price processes for all four countries (see section 3.1) are assumed to share the same fictive stochastic parameters. The starting mean value is assumed at 50 Euro/MWh with a drift of +1 Euro/MWh towards the end of each year. The volatility is expressed as a standard deviation before mean reversion at 1.5 Euro/MWh, while the mean reversion coefficient κ is set at 0.01. Markets are non-correlated, except for one special case, where the effect of high market correlation is analysed by assuming a correlation of 0.9 of market A with B, C and D.

Regarding the stochastic line failures (see section 3.2) we assume that on average three annual interruptions occur with a normally-distributed duration with expected 50 hours per outage. The line failures are assumed to occur with a Poisson-distributed frequency with a λ of 3. The spike mean reversion parameter κ, reflecting the speed of return to nominal capacity after a line outage, is set at 0.05. The average failure duration of 150 hours per year corresponds to 1.7% outage per year, which is regarded to lie in a realistic range (Lindén et al., 2010 and Waterworth et al., 1998).

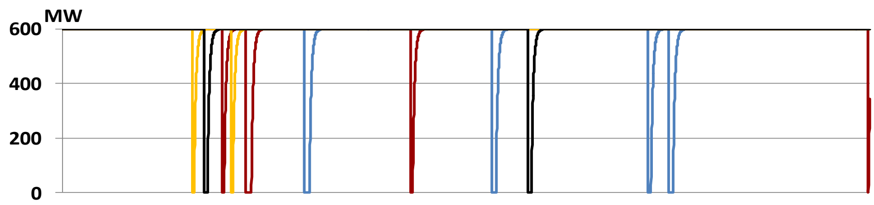

Figure 2: Exemplary outage results for the four interconnectors over a full year

The wind time series is based on measured wind data at the FINO1 platform in the South-Western part of the German sector of the North Sea for the year 2006. It has been processed into an hourly production pattern accordingly to Nørgaard et al. (2004) and approximately adjusted for wake effects. The 600 MW offshore wind park is assumed to have a lifetime of 25 years, about 4475 full load hours, investment cost of 2,450 million Euro/MW and operational expenditure of 0.07 million Euro/MW/year. These assumptions on the offshore wind park are based on ENS (2010). Apart from the rather high value for full load hours derived from wind time series, these numbers are in line with Deloitte (2011) and assessed to be realistic for the nearest years to come.

4 Quantitative results

The quantitative results we obtain and discuss further are different for wind park and transmission system operators. For the offshore wind park, the Internal Rate of Return (IRR) represents the value of the wind park and therewith the investment incentive. We consider expected mean IRR and the standard deviation of the IRR from the Monte Carlo simulations. For the TSO, the income from the interconnection operations forms the basis to evaluate the interconnections and therewith the investment incentive in additional cables. The TSO collects the income as congestion revenues, also called congestion rents, which are income from price differences on the participating spot markets and the implicit energy flows between them. We consider the expected annual mean congestion revenues as well as their standard deviation derived in the same Monte Carlo simulations as for the wind park.

4.1 One country – benchmark case

In the benchmark case, the offshore wind park is only connected to one country and is thus fully integrated into that one market. In case the wind park receives a guaranteed price in form of a feed-in tariff, the wind park is not exposed to the volatility of that market and all Monte Carlo simulations result in the same IRR for the wind park (see Figure 3, left). In case of a fixed price premium paid out in addition to the market price, the wind park is exposed to the underlying volatility and the Monte Carlo simulations yield a normally distributed outcome of the IRR (Figure 3, right). We have designed the cases in such way that the expected mean IRRs for feed-in tariffs and premiums are the same in the benchmark case, namely 9.8%. The difference in attractiveness of the two cases lies in the different standard deviation – The higher the standard deviation, the higher the riskiness of the project. The Feed-in premium case yields in a standard deviation of 0.4%-points. This result forms the basis of comparison for our further analyses.

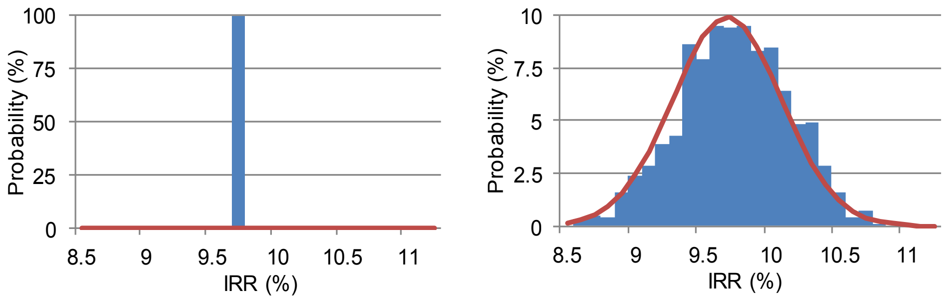

Figure 3: Wind park IRR for feed-in tariff support (left) and price premium support (right)

The congestion revenues for the TSO are assumed to be zero in the benchmark case, meaning that we only consider and compare the additional income generated by the new cross-border connections in the offshore hub in the two to four country cases.

4.2 Home country case

In this case, the offshore wind farm has primary access to its home country – where it is remunerated at the market price plus a price premium – and secondary access to the other countries, where it is only remunerated at the respective market prices. Quantitative results are depicted in Figure 4 and show that the average IRR increases with the number of markets while the standard deviation decreases. The average IRR can be increased from 9.8% under the connection to one country up to 10.3% under the connection to four countries. The marginal benefit of each additional connection is decreasing. In addition to an increase in IRR, the standard deviation, which we use as indication for riskiness of the investment, decreases when adding more countries, in our simulations from 0.4%-points in the benchmark case to 0.32%-points in the four country case.

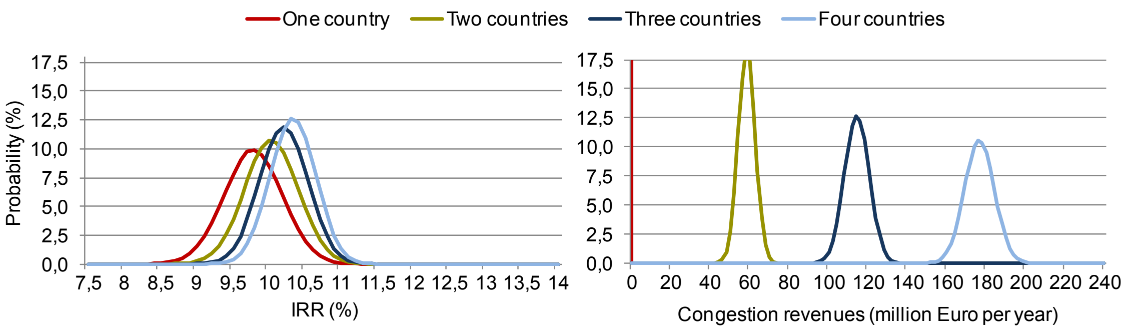

Figure 4: Wind farm IRR (left) and TSO congestion rents (right) in the home country case

Considering congestion rents (Figure 4, right), they increase with each additional connection and exceed the level achieved under primary market access by approximately 10 million Euro. The volatility, expressed as standard deviation of the congestion rents, increases from 4.3 to 6.3 million Euro when changing from two to three connected countries. Continuing to four connected countries, a further increase to 7.5 million Euro can be observed.

4.3 Primary market access

In cases where primary access is chosen as regulatory framework, the wind park operator has full benefit from the additional connections, whereas the TSO can only use the residual capacity. The wind park can choose into which market it sells the electricity and can therewith achieve a higher income from choosing the highest price at any point in time – the more countries are connected, the higher the value of the wind park (see Figure 5, left).

As already shown in Schröder and Kitzing (2012), the option to be connected to different countries increases the value of the wind park significantly. The value of the wind park is here expressed as mean expected IRR and increases with up to 33% in the four-country case compared to the benchmark case (up from 9.8% to 13.0%) when assuming a constant feed-in premium. In addition to an increase in IRR, the standard deviation decreases more than in the home country case, in our simulations with up to 42% (down from 0.4% to 0.24%). This is due to the fact that the wind park is less exposed to the volatility of market prices in one country as it has the option to switch sales to any other country whenever a low price period occurs. We conclude that the wind park operator will in this regulatory regime benefit from any additional connections: he can expect a higher IRR and at the same time a risk reducing effect. The risk-reducing effect is increased when taking line failures into account, whereas the expected project value and the risk reducing effect is decreased when considering correlation between the market prices of the participating markets. In our example, the IRR decreased by 0.6%-points when considering a two-variate correlation of all countries with country A.

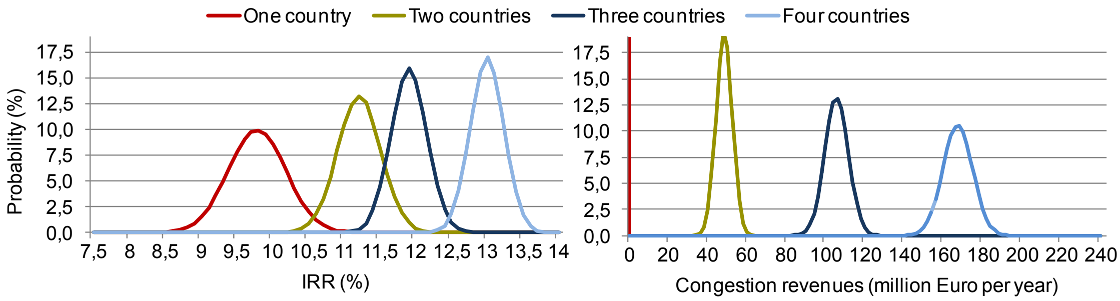

Figure 5: Wind farm IRR (left) and TSO congestion rents (right) in the primary access case

For all interconnector capacity that is not utilised by the wind park operator, the TSO collects congestion revenues from price differences in the adjacent markets. Figure 5 shows the expected amounts and probability distributions for this income. Compared to the two-country case, the expected income increases with 119% in our simulations (+58 million Euro) when adding one more country, and yet another 61 million Euro to 167 million Euro with addition of the fourth country. This is due to the fact that in the chosen set-up, single interconnectors have the same capacities and an even number assures a better asset utilisation than an odd number of lines. As an example, in periods without wind generation, one interconnector can export while another one imports. In a three-country case, this leaves the third interconnector idle. In a four-country case, the constellation is symmetrical again. Regarding volatilities, it becomes apparent from the simulations that – contrarily to the wind park operator – the TSO faces higher volatility in income when more countries are connected to the offshore hub. This is the case for markets with no or low correlation, since the additional volatility of each market adds to the overall fluctuation in price differences, which is the major income source for congestion rents. In a situation where the adjacent markets are highly correlated, both the level of income and the standard deviation decrease significantly.

4.4 Offshore price hub

In cases where the regulatory framework constitutes an offshore hub which forms its own price area, the wind park operator will not be able to choose on which market to sell his production. The offshore wind park will be subject to the price that forms in the offshore hub. This price is dependent on the price levels and price differences in the neighbouring markets as well as the overall available interconnection capacity. The flow in the connections from the wind park and the different countries is determined in implicit auctions. In almost all realistic situations, there will be at least one connection from the wind park to a country which is not congested, and the offshore hub price will thus equal the price of that market. This will typically not be the highest available price (Schröder and Sundahl, 2011). Therefore, the wind park will be valued at a lower level than in the case of primary access.

As was discussed in Schröder and Kitzing (2012), the model results reveal an interesting characteristic of how this regulatory framework impacts the wind park under the assumption of identical interconnector capacities. When two countries are connected to the offshore price hub, the hub will always form a price that corresponds to the lower of the two prices; therefore the impact is very significant with a decrease of ca. 15% (from 9.8% to 8.4%). In a case of three countries, the offshore price hub will form a price that corresponds to the median of all three prices. Some of the impact of the two-country case is mitigated. In a four country case, however a price will form that corresponds to the second lowest of the four market prices. In terms of riskiness of the project, i.e. standard deviation, the different country-cases show similar distributions as with primary access – a higher number of countries coincides with a lower standard deviation. The resulting IRR probability distributions are illustrated in Figure 6. The differences of the cases are much less pronounced if there is significant price correlation between the markets of the countries especially when including periods of equal prices.

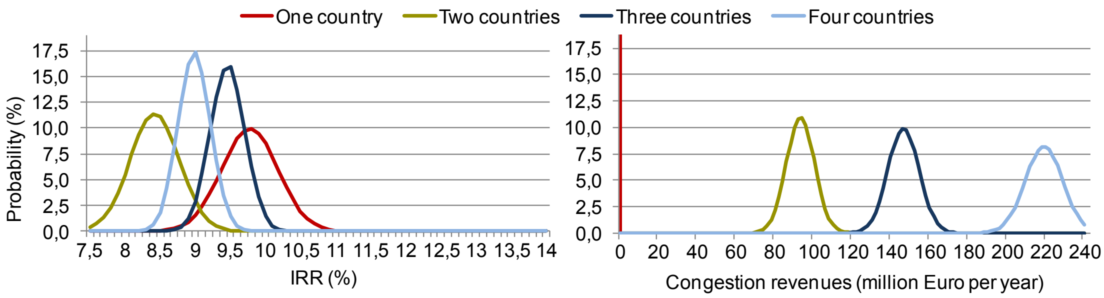

Figure 6: Wind farm IRR (left) and TSO congestion rents (right) in the offshore hub case

In the case of nodal pricing in an offshore hub, the TSO has access to the full interconnection capacity as the production and energy flows from the wind park is integrated in the overall market. Therefore, the TSO is able to collect more congestion revenues – the increase is in fact the same amount of revenues that the wind park operator loses in the offshore hub regime compared to primary access. The annual revenues lie in our simulations for each country-constellation 45-52 million Euros higher than in the primary access case.

It can be noted that the two-country case, which is the least attractive for the wind park operator is not the best case for the TSO, as the TSO's revenues increase with addition of more countries simply because more energy flow becomes possible. Also, the connection to a fourth country is not beneficial for the wind park operator, where it is for the TSO. In these cases, opposing interests of wind park operator and TSO could hamper the (further) construction of an offshore hub.

4.5 Special case: line failures

Line failures are a special case for this analysis, as the loss caused by line outages is a real reduction in energy flows between countries. Here again, it is a question of the regulatory framework in who is exposed to a potential loss from line failures – the wind park operator or the TSO. If the wind park operator is not compensated for line failures of the offshore cables, he bears risk of income loss from not being able to sell the power he produces. Figure 7 shows this situation for connection to one country on the left. If the wind park is connected to additional countries (each having similar risk of line failure) and has access to any of the other markets, then the wind park is less exposed to income loss the more countries are added, because it becomes less probable that all lines fail at the same time. Figure 7 shows that the income risk is nearly fully mitigated by four connections. This finding is in line with Macharey et al. (2012), who analyse possible interconnections between single German offshore wind clusters and conclude that meshed offshore structures can, even within one price zone, have a considerably risk-reducing effect and be profitable.

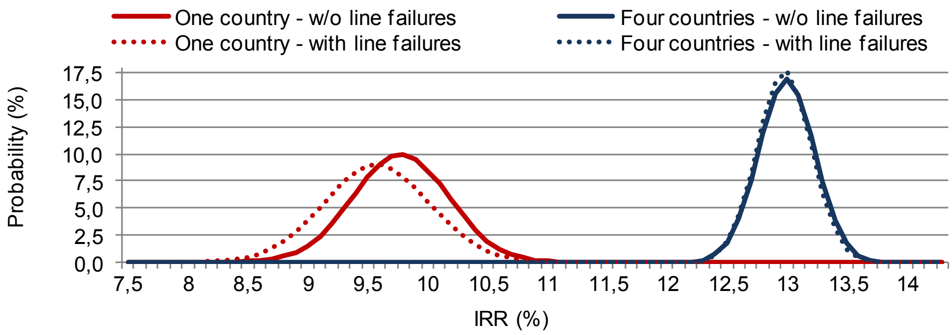

Figure 7: IRR probability distribution changes for the wind park considering line failures

This result can be of significant impact for the future valuation of wind parks in offshore hubs, especially in a regulatory regime with offshore hub pricing – the risk reducing effect on line failures might mitigate some of the disincentives for offshore wind park operators in the construction of an offshore hub. However, in a regulatory regime where wind park operators are fully or partly compensated for line outages, there will be no measurable or only limited impact on the wind park value. Here, the income for the TSO will, in addition to the losses from foregone congestion revenues, also be affected from the compensation payments for the wind park operator.

4.6 Comparison of all cases and sensitivity analysis

The overall comparison of all cases as illustrated in Figure 8 displays that wind park investors and the TSO have opposing preferences in regards to the regulatory regime. The TSO benefits clearly from a nodal pricing system in the offshore hub (all ‘offshore hub’ cases (yellow triangles) have the highest mean congestion revenues), whereas the wind park operator would prefer a regime with primary market access (green squares). Line failures have a much lower impact on cases than a high market price correlation (both special cases are connected to their respective reference cases by lines).

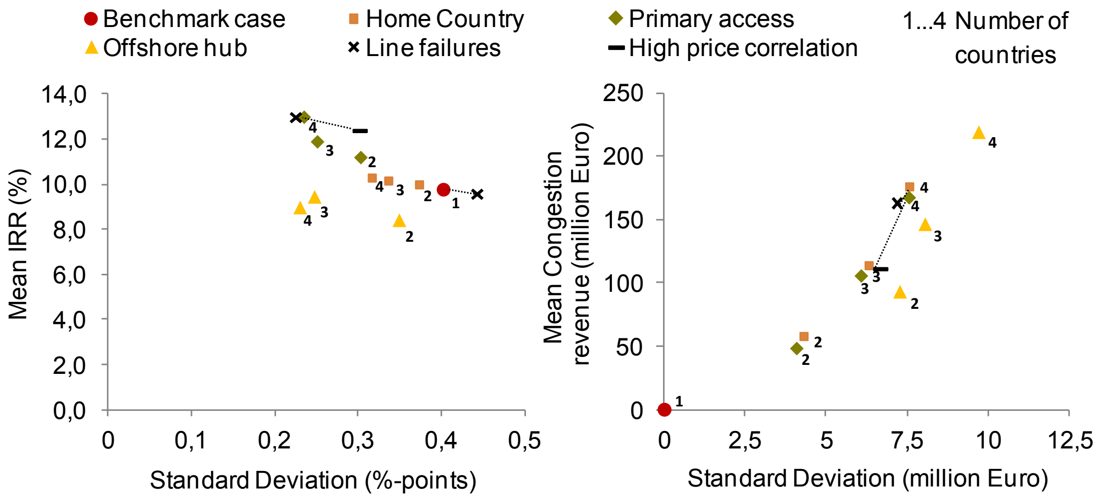

Figure 8: Overview of all case results for the offshore wind park (left) and the TSO (right)

The difference between primary access and nodal pricing is least pronounced for the three-country case: here, the primary access and nodal pricing cases differ only by 41 million Euro on average. The reason is a comparatively good case for the wind park under nodal pricing, which is at the expense of congestion rent income. This illustrates that option values between several cases are highly dependent on the underlying assumptions.

A sensitivity analysis for changed line capacities under nodal pricing shows that the wind farm's IRR standard deviation is only affected marginally, whereas the average return increases especially with the upgrade to 1200 MW (Figure 9, left). This is due to the fact that, starting with the benchmark value of 600 MW for all cables, the connection to one country has been increased in steps of 200 MW until 1200 MW. Reaching 1200 MW, the interconnection corresponds to two other interconnectors leading to a new price formation constellation, which explains the major difference to a capacity of 1000 MW. Regarding the congestion rents (Figure 9, right), the result fits with the expectation that additional interconnection yields decreasing marginal benefits.

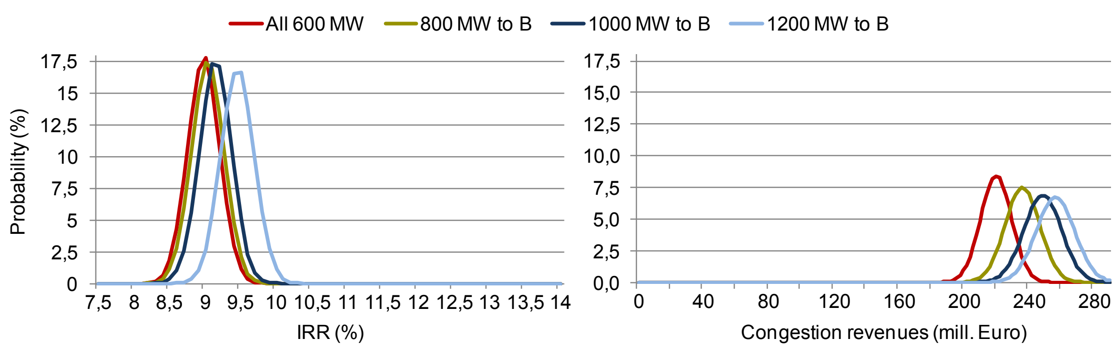

Figure 9: Wind farm IRR (left) and TSO congestion rents (right) for changed line capacities

5 Analysis and discussion

The investigated cases do not represent real conditions in terms of markets or technical options, but they carry some pure and archetypical characteristics of conditions for potential offshore grids in the European offshore territory. Therewith, they can serve as basis for the main points we wish to highlight. The results from the simulations show that the choice of regulatory regime has a decisive impact on the value of a wind park investment as well as for the income for transmission system operators. The impact can be both positive and negative for the different actors. Overall, we observe that the choice of regulatory regime has a re-allocative effect of benefits between the actors rather than creation of additional benefits. As long as connection capacities and market prices do not change between the cases, the aggregated benefits including the sale of wind power production and price differences between markets are the same. In case of primary access, more of the benefits are allocated to the wind park operators, and in the offshore hub with nodal pricing, more income is allocated to the TSO. Both regimes are feasible – it is a policy choice which regime should be implemented. In this regard, some considerations should be made.
First, offshore wind park are and will for the near future be dependent on financial support by specific instruments such as Feed-in tariffs of Feed-in premiums. If a regulatory regime is chosen that exposes the investor in offshore wind parks to market risk and at the same time to nodal pricing in the offshore hub, there is a significant risk of lower IRR when additional countries are added to the offshore hub. The attractiveness of investment is consequently decreased. In order to trigger an adequate amount of investment, the level of support needs to be increased. The higher support level could be paid from the additional congestion rents that the TSO incurs. By contrast, if a primary access regime is established, the wind park operator could benefit from significant windfall profits when additional countries connect into the offshore grid. To avoid socio-economically overly expensive support mechanisms, the level of support should be corrected downwards for each new country in the offshore grid.
Second, the level of cooperation between the countries needs to be taken into consideration. It will not always be possible to create an offshore hub with nodal pricing due to the high level of coordination. If one country has a well-established national Feed-in tariff system, only a strong ‘home’ country affiliation seems to be practically possible. However, an offshore hub regime with nodal pricing could especially become interesting for internationally coordinated support schemes in the future to ensure neutrality between the neighbouring countries (see Schröder et al., 2011).

In addition, the sensitivity analysis on interconnector capacities to different markets shows that quantitative results exhibit remarkable differences if the connection to one country reaches an integer multiple capacity of the capacities towards other countries. It should be emphasised that this also depends on the assumed generation time series and capacities.

We have limited our analysis to spot markets. In reality, balancing markets and their prices might be a very decisive factor in choosing on which market to sell. The cases and countries investigated do not represent a realistic market environment. Before drawing conclusions on real-world cases, the model should be calibrated to real market characteristics; especially the level and volatility of the markets are decisive. This, however, could first be applied for a real-world case where the interconnector capacities and market price characteristics are known and where the offshore node’s generation is handled differently than national onshore generation. A main simplification is that we look at real option values for the whole lifetime of the project. This supports transparency, but would probably not apply in real-world cases: additional interconnectors are first decided upon after the offshore wind farm comes into operation. So, for more realistic cases, a sensitivity analysis on additional interconnectors only after a certain number of years would provide valuable insights.

6 Conclusions

This paper presents an analysis on the economic effects of different regulatory regimes on offshore wind parks and transmission system operators in an offshore grid. Stochastic price processes and line failures are modelled for four spot markets. An offshore wind farm as part of a meshed offshore grid is connected to between one and four of these markets, experiencing different option values of additional interconnectors.

The analysis reveals two major insights: First, we have shown that the regulatory regime, including market access and pricing rules, has a significant impact on the valuation of assets in an offshore hub, both wind parks and interconnection capacity. The choice of regulatory regime can have both positive and negative impact on the actors. In our (fictive) case with connections to four similar archetypical power markets, the IRR for an investment in a wind park increases with up to 33% if the wind park has primary access to all markets. Contrarily, establishing an offshore hub with nodal pricing can have a negative impact on the IRR of up to 15%. So, the incorporation into an offshore grid is far from neutral for an offshore wind park. This leads to the question of how to compensate for possible losses or gains under the suggested regulatory mechanisms. Our results show this may need to be handled on an interconnector-by-interconnector basis: while the connection to a third country is beneficial for the offshore wind park under nodal pricing, the connection to a fourth country is negative.

Second, the incentives for the different market actors in relation to additional connections are very different and in some cases even contrary. This is particularly visible for the offshore price hub, where the wind farm's profit increases or decreases depending on the number of the connection to be made. It can contrarily still be a good business case to add a cable that is negative from the wind farm's point of view. Thus, the market actors such as transmission system operators and wind farm operators may take very different positions towards establishing new connections at different stages in the development of meshed offshore grids – which may hamper the construction of new lines that are beneficial from a holistic viewpoint. Both effects should be considered in future valuations of wind parks and offshore hubs as well as in the design of the regulatory regime for the offshore grid and the level of support for the wind park. Only then, an effective and efficient development of offshore wind in Europe can be achieved.

The sensitivity analyses that we have undertaken regarding different interconnection capacities shows that minor upgrades for single interconnectors improve the wind farm's income only marginally. A larger improvement is reached when a capacity corresponding to existing capacities (600 MW in the example) is added. As expected, the marginal benefit of additional capacity decreases from a TSO point of view.

Our results can be used when considering how to design a cross-border offshore hub, such as envisaged in the Kriegers Flak area, to make an informed decision. In order to balance incentives for investment and socio-economic efficiency, the support level, i.e. in our case the fixed price premium, could be adjusted according to changes in wind park value and riskiness.

The attractiveness of offshore grids for different market actors depends heavily on the choice of regulatory regime, including market access, pricing rules and support. Certain constellations of regulatory regimes create barriers that may hamper the development of offshore grids due to diverging incentives. If meshed offshore grids are to be built due to their socio-economic benefits, the effects described in this study should be taken into consideration when making regulatory choices.

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– Appendix VII –

Curtailment of renewable generation: economic optimality and incentives

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Curtailment of renewable generation: Economic optimality and incentives

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HIGHLIGHTS

- ▸ Curtailment of renewable generation can be optimal.
- ▸ Voluntary and involuntary curtailment categories.
- ▸ Compensation for involuntary curtailment should be provided.
- ▸ Asymmetrical balancing price provides incentive for voluntary curtailment.
- ▸ Network enforcement costs can be reduced per renewable generation.

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ABSTRACT

The loss from curtailing generation based on renewable energy sources is generally seen as an unacceptable solution by the public. The main argument is that it is a loss of green energy and an economic loss to curtail generation with near zero marginal costs. However, this view could lead to overinvestment in grid infrastructure and underinvestment in renewable energy sources. This article argues that some curtailment of fluctuating (variable) generation is optimal. We address the possible contributions to total curtailment from involuntary and voluntary curtailment. The costs of curtailment in terms of lost generation are discussed based on market price and support levels including the rationale for compensating generators for losses. The extent of actual curtailment is illustrated by examples from different global markets. In general, both the value of the curtailed energy and the amount of curtailed energy relative to total fluctuating generation is low but rising. Single generators may be affected considerably if insufficient compensation measures are in place. In the future, optimal curtailment will increase along with an increased share of fluctuating renewable generation. Extending renewable generation comparatively cheaply can be achieved by the installation of additional capacity at offshore locations until optimal curtailment levels are reached.

1. Introduction

The large investments in generation units based on renewable energy sources (RES) during the last years have increased the focus on integration costs of fluctuating generation. A part of these costs are related to the risk that in some hours, too much electricity is generated from these sources relative to network capacities and demand levels. Avoiding curtailment of this generation would require investing in network capacity including international interconnection and storage solutions which are very costly if used for few hours annually. Already today, more frequent occurrences of curtailment for renewable generators are observed in areas with high shares of fluctuating generation such as wind (Fink et al., 2009). The question whether to avoid this curtailment or not is debated increasingly. If deemed acceptable, different criteria can be taken as a decision basis (e.g. Huang and Liu, 2011).

An apparent option to minimise integration costs is to accept generation curtailment due to network constraints or market reasons. At first sight, curtailment of renewable generation might seem as a loss that should be avoided, but in certain situations, curtailment to a limited extent is an optimal solution with regard to total costs of providing electricity. This is illustrated in a number of papers dealing with transmission constraints, capacity investment and security issues (see e.g. Acharya et al., 2009; Rious et al., 2010; Ela, 2009).

Curtailment occurs today both as a consequence of constraints in distribution and transmission grids and a precautionary measure to secure stability of the system when there is high risk that large amounts of wind capacity might fall out during storms or as a consequence of network faults. This has been observed in areas in the US (Texas), Spain and Germany as well as smaller areas in

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other countries. From the generator point of view, the effect of curtailment is independent of the underlying causes. Therefore, all the different types of curtailment affecting renewable generators are addressed in this article.

This paper is structured as follows. In Section 2 we first provide an overview of the different causes and types of curtailment and categorise them with regard to underlying reasons. The comparison identifies (a) arguments for including curtailment as an option to reduce costs of integrating large amounts of variable renewable generation and (b) incentives that could be used to induce appropriate voluntary curtailment behaviour. From this, the question about optimality under both voluntary and involuntary curtailment and arguments for compensation arises. This is why we turn towards these topics in a next step. On the one hand, full absorption of all generation can lead to excessive network extension costs. On the other hand, compensation to generators is a key topic if we will induce appropriate investment in network reinforcement.

Section 3 analyses the behavioural aspects of voluntary and in-voluntary curtailment and the incentives that affect this behaviour.

Section 4 presents quantitative evidence for both voluntary and involuntary curtailment. A highlight is cast on the coincidence of curtailment and low market prices. Next, Section 5 provides a discussion on total cost arising from all curtailment types and whether they are based on the short-term value of the power. This is related to benefits in terms of investment and operation savings. Finally, Section 6 contains concluding remarks on the possibility of optimal curtailment and the necessary incentives to support optimal behaviour of both generators and networks.

2. Categories of curtailment

In this section, we categorise the types of curtailment based on the situation in which they occur and the rationale for voluntary and involuntary curtailment. We define curtailment as an instance when a generation unit produces less than it could due to its own marginal cost characteristics.

Network investments become increasingly dependent on the localisation of generation capacity also at distribution levels. Considering that simultaneous peak generation of different technologies in an area occurs only for a few hours per year, the marginal network investment per generated unit can turn out to be quite high. This stresses the importance of the localisation decision for this type of generation capacity. The curtailment of generation in hours with constraints can serve as an incentive for investors to find locations with least risk of curtailment. Ochoa et al. (2010) examine the distribution network capacity with variable generation sources in combination with active control and find that accepting 2% curtailment doubles the variable generation capacity that can be accommodated in a distribution grid. The location decision of new fluctuating generation, network tariffs and regulation of Distribution System Operators (DSOs) is discussed in Ropenus et al. (2011), also pointing to the potential incentives from curtailment and compensation rules.

International interconnection capacity relative to national generation and fluctuating generation capacities is very different among EU countries. This constraint can in some instances create a curtailment risk. It applies both in the general excess generation situation and emergency situations when more flexible generation reserves are required online and interconnection capacity to other areas cannot fulfil this reserve requirement. However, avoided curtailment is probably a minor benefit of additional interconnection capacity.

Table 1 distinguishes four reasons for curtailment. We will address them separately in the following. As shown by Burke and O'Malley (2011), it is possible that the different types of curtailment are correlated in time. If there is a risk of curtailment due to overall excess generation, there is probably also curtailment due to network constraints. The following table gives an overview of the different reasons and main features. Column one and two distinguishes voluntary and involuntary occurrences of curtailment and the responsible entity. Column three lists economic rationales for allowing curtailment and column four suggests the extent and the one responsible for compensation to generators.

2.1. Network constraints

Curtailment due to network constraints can be both voluntary and involuntary, but most focus has hitherto been on the involuntary curtailment and related problems regarding connexion of new renewable generation capacity. In many countries, RES producers enjoy priority network access at their nominal capacity, also referred to as firm access. We distinguish *voluntary curtailment* from involuntary curtailment by an ex-ante agreement between the RES investor and the network owner specifying the rules for amount of curtailment and possible compensation. In addition, the RES investor needs to sign this agreement voluntarily, i.e. network connexion may not be conditional on the existence of such an agreement. In practice, this could have several effects, e.g. (a) lower connexion charges than those under the mandatory regime if the RES unit agrees to connect at a different network node with possibly higher curtailment, or (b) connexion to a point with less expected curtailment than in

Table 1
Categories of curtailment situations.

Reason	Voluntary	Involuntary	Rationale	Possible compensation
Network constraints	Accepted in contracts—(at time of connexion)	Short term DSO—controlled generation reduction	Avoid overinvestment in transmission and distribution capacity, extension delays	DSO or TSO compensate based on market price and/or subsidy (legislation)
Security	Specialised market	Max. generation limits for a number of consecutive hours, mainly enforced by TSO	Reduce reserve capacity costs/ dynamic reserve dependent on variable generation	Separate market or compensation from TSO/grid users based on legislation
Excess generation relative to load levels	Low or negative power market prices induced	Generation limits enforced by TSO	Highest marginal costs generators should be curtailed if market fails	Compensation by TSO based on subsidy only to provide incentive for voluntary curtailment (legislation) no compensation for involuntary curtailment
Strategic bidding	Manipulate prices	–	Profit from exercise of market power	–

the mandatory benchmark situation. The additional costs associated with the connexion to a different, 'less-curtailment' node could be borne by the benefitting RES investor. *Involuntary* curtailment can take place temporarily due to delays in infrastructure investment relative to generation capacity. Building wind capacity can be completed in time spans from months to a few years, whereas investment in new transmission lines can have delays of up to 10 years. Involuntary curtailment caused by permanent network constraints could be combined with an obligation for the network owner (DSO or TSO) to compensate the generator at least partly for the loss incurred. This is important in order to provide an incentive for the network owner to build more capacity, and do it at a speed that balances the costs of network investment with the value of curtailed energy represented by the compensation payments. This point holds if the network operator is not legally obliged to build the additional capacity to avoid curtailment. Grid reinforcement is only rational when expected curtailment exceeds a certain level and can also be subject to lump-sum investment characteristics of network extensions. Economies of scale for network investments will reinforce the lumpiness of this investment and contribute to varying levels of curtailment over time.

Voluntary curtailment in networks is mostly associated with investments where the investor directly or indirectly finances the connexion lines to the network. For offshore wind projects, this constitutes a considerable part of the total investment amount in some countries. With high costs for offshore cables, the optimal investment in cable capacity is reduced somewhat below the expected annual maximum output of a wind farm (National grid, 2009). The investor thereby voluntarily accepts some curtailment due to a constraint in his own connexion cable. Naturally, there is no compensation associated with this type of curtailment, and it will not show in any statistics. Optimally, the marginal value of expected curtailed energy over the lifetime of the cable should be balanced with the marginal cost of increasing the cable capacity.

DSO and TSO networks are widely regulated entities based on their natural monopoly properties. Especially in Europe, the traditional regulatory approach was to make the connexion of new small to medium scale renewable generation capacity in distribution grids mandatory for the DSO. Reaching higher penetration levels, it has been shown that nonfirm connexion can lead to a larger amount of installed wind capacity (see e.g. Keane et al., 2007 or Bajor/Jankowski, 2011). Since mandatory connexion of renewable generation at full capacity has not always been possible without causing grid problems because of limitations and delays in grid reinforcement, the issue of compensation in curtailment cases has been added to the debate. The interaction between the DSO and the investor in distributed generation (DG) in terms of incentives and revenue has been covered e.g. in the IMPROGRES project (Ropenus et al., 2009). This report points to the plant location decision as an important decision that depends on regulation and connexion policies and affects the interrelated costs between DG and DSO in the specific DSO grid. New plant location decisions also affect the distribution of DG investment over DSO grids with different DG penetration and cost characteristics. For this decision to be efficient, one has to consider the *appropriate cost mechanism* for the DSO to affect DG location decisions. The new investor may be exposed to some costs, for example in the form of curtailment if he invests in an area with high network reinforcement costs. An incentive, for example no or reduced compensation for curtailment, is needed to consider alternative locations where there is less risk of curtailment because marginal network extension costs are lower. Regulated parameters as connexion charges and use of system charges can have such effects, but they can only vary within limits approved by the regulator. Setting connexion charges, the DSO is able to provide incentives for DG localisation, but this parameter is often regulated at shallow connexion cost that do not account for more widespread network reinforcement costs. An option is therefore to let a curtailment cost serve this purpose. A drawback of this approach is that this cost is quite uncertain as it is a revenue stream loss over the lifetime of the generation investment and depends strongly on changes in the level of compensation. Allowing curtailment with compensation could thus serve a double purpose: (a) avoiding overinvestment in grids and (b) providing incentives to renewable investors to locate their investments where the reinforcement costs are the lowest. Another aspect is that grid extensions typically require more time than erecting new RES capacity (10 years for overhead lines in comparison to 2–3 years for wind turbines, whereas underground cables are faster to build, but at higher costs). This leads to an inherent risk when planning optimal network extension and curtailment, and it is likely that actual curtailment deviates from the optimal level.

On the negative side of cost interaction, there is a cost element of DSO operation that depends on the support scheme for DG. If the curtailment cost of generation is to be borne partly by the DSO, the curtailment costs are higher under a fixed feed-in tariff. Under a premium or Tradable Green Certificate (TGC) scheme, the power market price tends to be lower at times of curtailment. For this reason, curtailment cost for the DSO is lower as well. This is efficient from an economic point as the cost of lost generation is reflected in the market price at the given point in time.

2.2. Network security and inertia

Network security is distinguished from the other cases by the following criterion: if it is not a capacity limit causing the curtailment, but limitations in other factors such as reactive power or risk of fast change in variable generation, we regard the curtailment as due to network security. In practice, simultaneous occurrences of these situations render a clear-cut separation difficult.

Grid faults and scheduled grid maintenance will cause occasional curtailment of primarily generators connected to the distribution grid levels. The DSO should optimally balance the effort to reduce grid faults with the compensation it has to pay to the generators in these cases. Security concerns in relation to possible grid faults and voltage concerns play an important role in determining how much variable generation can be allowed at certain points in the grid. The EirGrid/SONI (2010) study on wind penetration in Ireland illustrates this with regard to frequency concerns in the island system: beyond a penetration of 70%, curtailment might be required if no other measures are taken. Possible mitigation measures are conventional units providing inertia without providing reactive power or emulated inertia by adapting wind turbine control programs.

A separate concern is fast changes in fluctuating generation; curtailment also takes place as a precautionary action in cases where there is a high share of fluctuating generation expected and the system would lose too much capacity too quickly if wind generation shuts down during storms or local network faults spreading. In principle, this is a systems reserves problem and was especially relevant before fault overriding capabilities became a general property of wind turbines in new installations. However, with high shares of wind relative to load nowadays, there are times when the expected reduction of wind generation from forecasts coincides with low demand levels and requires considerable spinning reserves. Therefore, it can be necessary to curtail wind generators in hours ahead of the expected drop in generation (EirGrid/SONI, 2010). As for all reserves, the cost for this is shared among use-of-system charges contributors which can be consumers only or both consumers and generators depending on national legislation.

2.3. Excess generation

When the level of variable generation reaches a high penetration, there will be incidents when generation exceeds a certain maximum load that is regarded as an upper border for system stability, e.g. in an island system. The effect of different curtailment thresholds — i.e. the penetration wind power may not exceed — has been quantified for Great Britain by Gardner and Papadopoulos (2012). In a system with a large amount of installed wind power, large amounts of curtailment can be avoided if this threshold can be raised. Spatial leveling effects could provide a similar effect, although this requires distant and large-scale interconnection. Regarding historical data for West Denmark, wind generation exceeded load during 33 h in 2009 (Grohnheit et al., 2011). For a considerable larger number of hours, wind generation exceeds the load after "must run" generators. As the share of variable generation sources in the power systems increases with investments to comply with the EU 2020 RES share targets, such excess generation situations will occur in more areas and for more hours.

The involuntary curtailment in this situation is more problematic for the individual RES operator than from a system point of view since the value of the generation and the market price is low with excess generation. Corresponding to this, voluntary curtailment is also more likely to take place, especially if some generators are not receiving production-dependent market support. This situation is further covered in Section 3.3: *voluntary curtailment and optimality* (see Fig. 3).

2.4. Strategic bidding

In markets that sometimes experience less than perfect competition, there are potential gains from strategic bidding in the market. Directly related to curtailment is capacity withholding from the market to drive up the market price. Withholding generation capacity with low marginal costs only makes sense for society when market prices are low. The largest gain from withholding capacity is at times of high prices because a small capacity at the steep part of the merit-order curve makes a big difference. In such a situation, this form of curtailment to exercise market power leads to socio-economic losses.

3. Voluntary and involuntary curtailment—optimal behaviour and incentives induced by compensation

The focus of the international discussion has been on the involuntary curtailment of renewable generators, namely the lost "green generation" and associated financial losses for curtailed generators. In this section, we provide an overview of the arguments about involuntary, yet socio-economic optimal curtailment. However, there are also situations when generators curtail voluntarily even though they generate at very low marginal costs. The relation to market prices is as follows:

- Involuntary curtailment occurs at all price levels, but more often at low prices.
- Voluntary curtailment occurs predominantly at low market prices.

Economic behaviour from generators suggests that generation will be held back only when this is profitable. Involuntary curtailment will take place initiated by the DSO or the TSO for the reasons discussed above. We start with optimality in relation to involuntary curtailment and then turn to private and social optimality in relation to voluntary curtailment.

3.1. Involuntarily curtailment and optimality

Involuntary curtailment mainly happens due to network constraints as discussed in the previous section. The question is then whether this type of curtailment is optimal with regard to avoiding other costs, mainly investment in network capacity and reinforcement.

From a social point of view, over dimensioning the capacity of both fluctuating generation and network capacity should be avoided. This does not imply that fluctuating generation always has to be lower than consumption. However, if fluctuating generation causes excess generation, this should be reflected in revenue from market prices to reach an optimal investment level for RES units. If local constraints in the grid are expensive to relieve, this should result in some curtailment of generation. This, in return, should provide incentives to network operators to invest only until the costs of expected curtailment are lower than additional network extensions.

Similarly, the investment in interconnection capacity should be based primarily on market price signals. This reasoning means that investment due to low power market prices in excess generation situations should only take place if associated losses correspond to the investment costs of additional network capacity. This implies that network extensions partly depend on power prices and power market design, possibly applying nodal pricing as a basis for network extension calculations (see Joskow and Tirole (2003) for a comprehensive overview on the theory of merchant transmission investment).

Finally, we would like to highlight the difference between involuntary generator and load curtailment. On the load side, it is seldom an option to dimension the grid to sometimes being short of network capacity. However, on the generation side this option is relevant. The main reason is that the value of lost generation corresponds to the marginal power price in the market, whereas the value of lost load for the consumer is much higher. Only when the value of lost load can be maintained at a low level and identified through interruptible connexion contracts with large customers, the load curtailment becomes relevant as an alternative to grid extension.

The optimal curtailment according to Fig. 1 is at different levels in the different grids and depends on their characteristics. Grid A should have higher curtailment levels than grid B. As long as this is a part of the decision parameters affecting investment decisions, this does not necessarily imply that the penetration of renewables should be lower in grid A. If the expected curtailment deviates from the optimal level, it is however important that investment incentives for generation capacity locates investment where curtailment costs for the additional investment is the lowest.

The marginal cost of avoiding curtailment in the figure reflects a static situation with a given level of fluctuating generation in the grid. If new curtailment-increasing generation capacity is added, marginal avoidance costs are, ceteris paribus, lower. Assuming a correct incentive structure, this induces investment in grid reinforcements, but only to the point where marginal costs equal the losses from curtailment at the new level of renewable generation capacity. For a static situation, the incentive structure may in practice be given or supervised by the application of reference network models to monitor the optimal levels of network extension and curtailment. The avoided curtailment is the accumulated amount during the lifetime of the alternative network investment. Marginal cost of curtailment can be interpreted

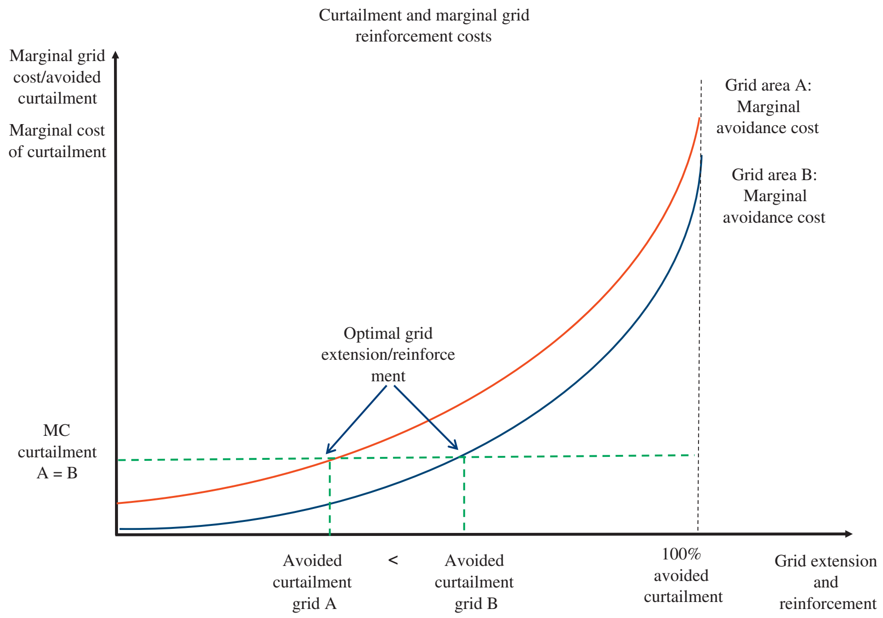

Fig. 1. Curtailment and marginal grid reinforcement costs.

Table 2
Suggested compensation for different curtailment situations and in various regulatory regimes.

		Curtailment compensation		
		Generator compensation	By network company	By society
Source of curtailment and regulatory regime				
1: Network constraints (optimal curtailment)	Network constraints—no pre-agreed level of curtailment	market price—with loss of subsidy	Partially, e.g. at market price if responsible	No
	Network constraints-curtailment until pre-agreed level controlled by regulator	None below level, fully above level	None below, fully above level, if responsible	No
2: Network extension delays	Priority dispatch granted previously	Yes, fully	Market price part, if responsible for the delay	Fully, if lengthy permission procedures responsible for the delay; if network company responsible, only support part
	No priority—new installations	Market price—with loss of subsidy	Partially, e.g. at market price if responsible for delay	Partially, e.g. at market price if lengthy permission procedures responsible for the delay
3: System security concerns	Curtailment due to general system security concerns	None, in line with emergency rules for all other generators	Not responsible	No
	Curtailment specifically due to technology issue (uncontrollable sources)	Market price—with loss of subsidy	Not responsible	Partially, e.g. at market price if TSO preorders curtailment of certain technology
4: Excess generation (zero or negative market price)	Excess generation relative to load	Market price, but this should be zero	Not responsible	Market price, but this should be zero
	Voluntary curtailment incentive in excess situation	Only subsidy part (in excess of market price)	Not responsible	Correction of incentive for zero marginal cost generators with feed-in or premiums

as an average of the market price in the hours with curtailment. This is independent of the actual grid and thus, marginal curtailment costs are identical in areas A and B for the same hours. This argumentation assumes that there is the same market price for generation from A and B grids instead of locational prices.

3.2. Compensation for generators

To avoid in-optimal high curtailment, compensation should be considered in all the situations where the one responsible can be identified and this entity can affect the level of curtailment. We focus this section on using compensation as an incentive for implementing optimal curtailment levels and localisation of new generation capacity. An overview of the most relevant real-world cases and suggested curtailment compensation levels are provided in Table 2.

Optimal curtailment levels in power systems with considerable fluctuating generation should in the long term (static) situation be determined together with optimal network capacities. If this is possible, for example by using network reference models and allowing the regulator to pass the results to the network owners instructing them to establish the optimal network level, there is no need for compensation. However, with the relatively fast change in fluctuating generation to be integrated, it will in most cases be the local network owner (DSO) that has the best knowledge about marginal grid costs and marginal curtailment from adding more fluctuating generation. A regulation that uses costs in terms of compensation payments to incentivise the DSO to invest in grid until marginal costs matches the marginal compensation payments might be a solution when there is an information bias in favour of the DSO. In this case, compensation is needed as a necessary incentive for the DSOs. In the discussion of inducing correct investment incentives for DSOs, we assume that network regulation does not allow compensation payments for curtailment to be fully included in the revenue cap for the DSO. The DSO will thus prefer a situation where the combined grid investment and curtailment costs are minimised, maximising their profits. In Table 2, these two regulatory options are treated in case 1.

The important point is to provide incentives for the DSO to invest in network capacity, until

marginal network costs = marginal expected compensation for curtailment over the lifetime of the network investment.

The lower the value of curtailed fluctuating generation and therewith the compensation payment, the higher the level of optimal curtailment will be—thus, a higher share of fluctuating generation will lead to higher levels of optimal curtailment.

Ideally, compensation fulfils both the following conditions:

- Curtailment being only partially compensated should provide DG with an incentive to invest in an area where this is the least likely to happen.
- Curtailment compensation payments from the DSO to the generator should induce the DSO to invest in grid reinforcements until an optimal level is achieved.

Table 2 provides an overview of the most relevant curtailment compensation situations. We distinguish 4 sources of curtailment based on Table 1. Then we suggest whether there is to be no curtailment compensation, i.e. the loss is to be borne entirely by the generator, whether it has to be paid by the network company or the society in general for example financed by general system charges paid to the system operator. By the term 'network company', we refer primarily to a regional/local entity where network congestion may occur, whereas a system operator is responsible for overall system security concerns. Society is a generic term that could in practice be represented by the system operator, i.e. costs attributable to society could be levied on TSO charges to final customers. Compensation can be fully including the quantity based support received by renewable generators or partially based on power market prices. If fully compensated, the DG does not have an incentive to locate the investment to less constrained grids and therefore this option is mainly for obligations regarding existing generation capacity. Next, we distinguish specific regulatory constellations. They are not exhaustive, but capture occurrences with specific relevance to renewables support and connexion regulation, and are addressed in the following paragraphs.

Two regulatory options to induce network investment and corresponding optimal curtailment exist as illustrated under case 1. One regulatory option addresses a case where certain maximum curtailment levels have been agreed upon before connexion of new generation to DSO grids. This can be classified as a *quantity-regulatory* approach. In order to set locational incentives, these levels could differ geographically. Yet, they need to be monitored or set by regulators, e.g. with the help of network reference models. Until the pre-agreed level which is the optimal level, no compensation is to be given, whereas beyond it, the responsible party compensates fully the lost revenue. With expected and announced curtailment costs in a particular grid, the generation investment in other grids with less costly constraints would be induced. Such expected curtailment cost up to pre-agreed level can set correct locational incentives for distributed generation units. This would be an incentive similar to reducing connexion costs in grids with less capacity constraints. We find that this option should be applied where the changes in both grid and fluctuating generation capacity are expected to be gradual and limited, or the majority of curtailment is expected to be due to transmission constraints.

The option in the first row differs from this regulatory solution by the virtue that the regulator does not have to set an optimal curtailment level, but that it results from an equilibrium as suggested in the previous section on involuntary curtailment and optimality. This can be classified as the alternative *price-regulatory* approach. The responsible network company gives a partial compensation that could be set at the market price level by the regulator. This results in optimal short- and long-term incentives for both DSO and new generators; building extensions is speeded up to shorten the periods with high compensation payments. In addition, permanent curtailment remains allowed in the long-term and the network company will choose them such that curtailment expenses are marginally identical with network extension costs. At the same time, the characteristic that compensation is only partial induces locational incentives to project planners. We find that this option should be used when changes in network end user demand or distributed fluctuating generation are relatively large and uncertain. This regulatory option should also be preferred when curtailment is expected due to constraints in several small independent distribution grids.

As case 2, we regard network extension delays as a cause which can already impose a problem at low system penetration levels. Priority dispatch has typically been granted under feed-in tariffs. This implies that *existing* generators have based their investment decision on the right to generate whenever possible. This contractual basis remains to be served in the case of network congestion, either by full compensation distributed on the network company responsible for delays and society or entirely by compensation from society. By network extension delays we mean local grid reinforcement but exclude the delay of direct connexion. New generation capacity should not be granted priority access if power markets work sufficiently well. Compensation for curtailment to new capacity should be paid partly by the responsible party at market price levels. This would induce investment where the loss from curtailment is expected to be the lowest due to anticipated delays (lost support).

If system security concerns (3) cause the curtailment, the authors suggest that no compensation is to be given if the curtailment follows the same rules as for other generator technologies. If, however, technology-specific issues such as high uncontrollable generation relative to system load legitimate the curtailment, compensation is to be paid for by the system operator.

Curtailment caused by system wide excess generation (4) can be optimal as discussed in the following section, but when this occurs there need to be incentives in place to make the highest marginal cost generation curtail output first. In case of market dominance of quantity supported renewable generation e.g. feed in tariffs or premiums these generators will not curtail until the market price becomes negative corresponding to the support they give up. Zero cost generators should curtail before those low marginal cost generators that are characterised by high stop and start costs. By compensating renewable generators for the lost support, they will voluntarily curtail generation at a market price of zero as discussed in the following section on voluntary curtailment. This type of compensation is only relevant if there is not enough zero cost generation that curtails at market prices around zero.

In conclusion, we advocate compensation at different levels for a number of cases. These are pragmatic suggestions balancing the desire for locational incentives for generators and to induce the network operator to achieve an optimal curtailment level. We generally prefer compensation at market prices when the curtailment is due to constraints in the network and no compensation when the curtailment is due to overall excess generation and all generators are treated similarly.

3.3. *Voluntary curtailment and optimality*

In the case of a generator maximising his profits, voluntary curtailment means that curtailment is a private optimal solution given the constraints he is facing. The issue is then if this private optimality also corresponds to a social optimal situation. In general, as the renewable low marginal cost generators are receiving production based support (case I and II below), the curtailment is also social-economically optimal if it is privately optimal. The problem is that it is necessary to have negative prices if a renewable generator should voluntarily give up the production support earned from feed-in tariffs or premiums.

Three types of renewable generators support and incentives can be distinguished:

I. Full fixed feed-in support (no dependence on market price).
II. Feed-in premium + market price.
III. Market price only (beyond support period, or in markets without support).

Fig. 2 illustrates how these three types of zero marginal cost generators enter the short term supply curve at different levels depending on the support level. Fixed feed-in supported generators will supply until the negative market price equals the quantity based support they receive. Even if they do not participate in the market the one responsible (TSO or handling agent) will pay the support and instruct the generator to reduce supply (curtail) at this price level. Renewable generators with premium will supply at less negative price and zero cost renewable generators without support will supply at zero price.

Fig. 3 depicts an exemplary annual price duration curve. The flat parts illustrated in Fig. 3 correspond to the short term supply curve with flat parts for certain technologies as corresponding to levels given in Fig. 2. Normally the fluctuating wind and PV technologies will be represented by the zero marginal costs and therefore enter the simplified supply curve first. However, including loss of support from feed-in tariffs etc. should place these technologies with a flat supply at negative prices. This is observed in some markets today, but other markets do not publish these supply bids and therefore this behaviour can only be observed in the flat parts of the price duration curves. In Nicolosi (2011) this is illustrated in modelling scenarios including voluntary curtailment, forced curtailment at zero price and forced curtailment at −150€/MWh that weakens the priority feed-in primacy under a feed-in tariff.

Avoiding wind curtailment with storage capacity is a very relevant option in systems with a high fluctuating share. The high price volatility provides even without zero and negative prices associated with curtailment incentives to invest in storage capacity. With more storage capacity, wind curtailment due to excess generation on the market will be reduced. All the market price related price volatility is included in the investment decision. The non-market curtailment (local grid constraint or emergency reserve) should add to the profitability of investing in storage. This means storage investment in the DSO grid could become relevant if storage technologies here are competitive to storage elsewhere in the system. In Denmark this will probably not be the common situation as competitive storage is still mostly associated with hydropower in Norway, but the alternative of electricity based heating with heat storage in grids with constraints that lead to wind curtailment is relevant.

3.4. *Asymmetry of balancing costs and voluntary curtailment*

Skytte (1999) pointed to the asymmetry of regulating costs between up regulation and down regulation premiums and the

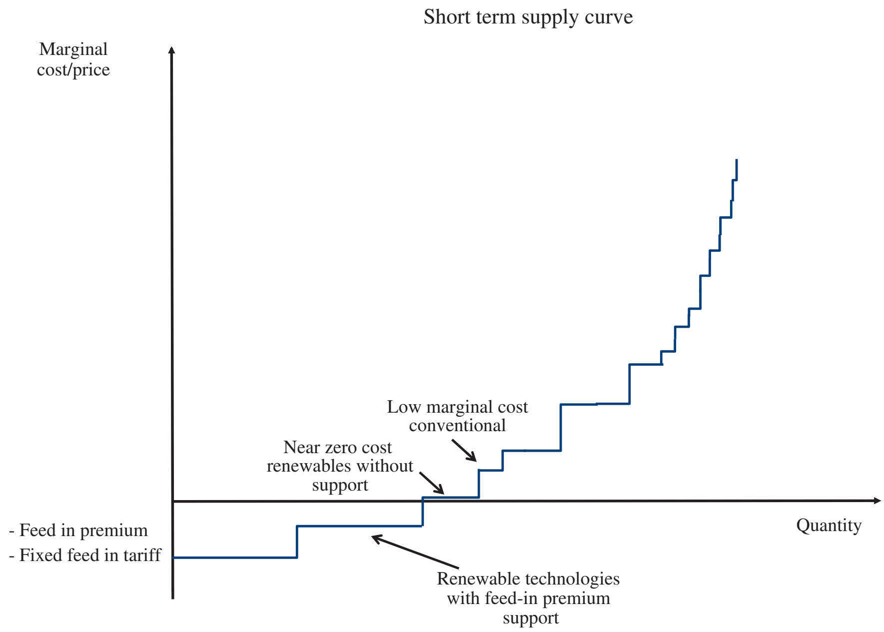

Fig. 2. Short term supply curve with quantity based support for renewable technologies.

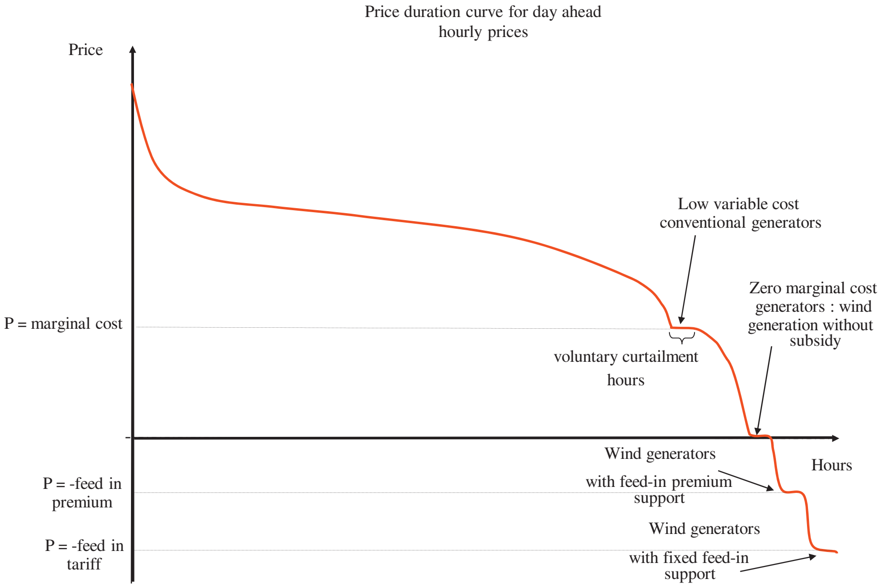

Fig. 3. Voluntary curtailment and the price duration curve.

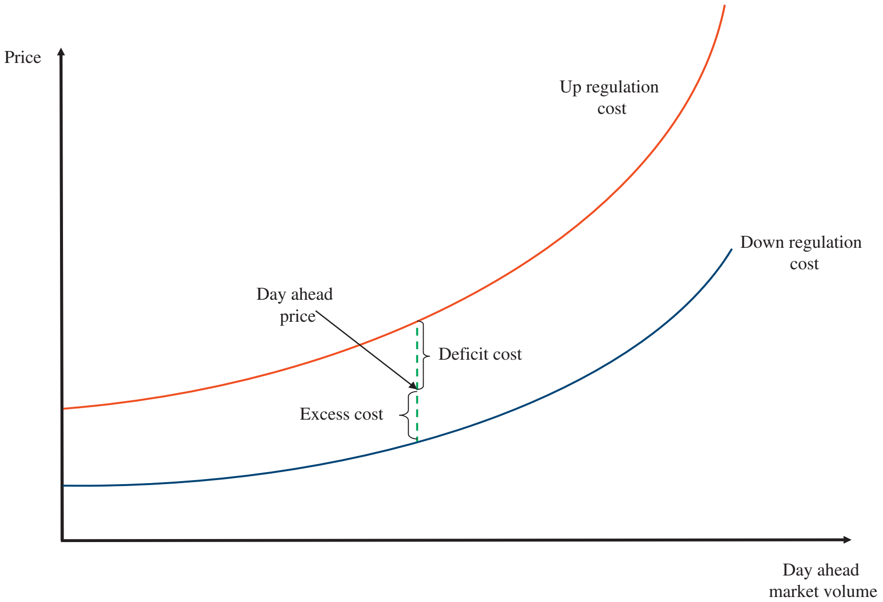

Fig. 4. Asymmetrical balancing costs due to the convexity of the supply curve.

impact on bidding incentives for balance responsible generators. With an estimated equation for up- and down-regulation prices in the Oslo area of the Nordic market, he found that down-regulation premiums are lower than up-regulation premiums. Other markets do not necessarily show the same pattern, as this depends very much on the composition of technologies, imbalance charge and regulating market design. This possible asymmetry provides an incentive to bid less than expected output at the day ahead market and on an average, realise more excess generation than deficit generation (Zugno et al., 2010). This holds for both a positive and negative correlation between wind generator and overall system deviations relative to their schedules. A comprehensive analysis of the properties of the different price schemes for balancing markets and the incentives for generators are given by Vandezande et al. (2010). Here we focus on the different sources of asymmetry that provide incentives for voluntary curtailment.

For a system with a single price for up and down regulation, the situation is illustrated in Fig. 4.

In a system with a single imbalance price, the asymmetry is due to the fact that the upward regulation prices are right hand costs and downward regulation prices are left hand costs of the supply curve. The asymmetry is illustrated in the figure above with the vertical distance from the day ahead price level. To balance the asymmetry, the generator will have to end in the excess generation situation as he is incurring the lowest balancing cost here. It could for example be optimal to have 2/3rd probability for experiencing an excess in real time and only 1/3rd for experiencing a deficit. This will be achieved by bidding less than actually expected generation at the day-ahead market, which eventually corresponds to voluntary curtailment in a number of instances (Zugno et al., 2010).

Furthermore, the largest absolute supply deviations due to fluctuating generation can be expected when generation from these sources is high. The market prices in these situations will at the same time be considerably influenced by this supply at near zero costs (Jacobsen and Zvingilaite, 2010; Andor et al., 2010) and this might further induce voluntary curtailment due to asymmetrical balancing cost under low day ahead prices. In general, the price of down regulation is more correlated with the spot price than is the price of up-regulation (Skytte, 1999). By down-regulating the loss is the sales revenue from the spot market reduced by any possible saved fuel.

4. Quantitative case studies

4.1. Involuntary curtailment in Germany

Germany is among the largest wind energy markets of the world. Electricity demand centres are chiefly in the West and the South, whereas wind is mainly sited in the Northern coastal regions and the East. As the planning and permission procurement procedures for network extensions are typically longer than for wind farms, congestion in the high wind penetration regions is handled by curtailment as a means of last resort after other measures have been taken. If the curtailment is due to system stability concerns at the transmission level, no compensation is given; if the curtailment is due to network congestion, generators are to be compensated for their foregone income. The obliged network operators need to prove that all other measures were taken in order to be allowed to recover curtailment compensation expenses through network charges.

An in-depth review of the current legal situation in Germany can e.g. be found in Brandstätt et al. (2011), who analyse the economic effects of curtailment on German wind generators under the existing feed-in tariff regime. They propose to change the existing scheme of possible involuntary curtailment towards a scheme of voluntary curtailment in the context of negative electricity exchange prices. Generators should always have the right to produce at their respective feed-in tariff, and network operators can buy voluntary curtailment by means of a tendering scheme. This leads to a situation where curtailed generation is remunerated at prices higher than feed-in tariffs, while negative price spikes are avoided. Such a scheme would foster the investment in additional wind capacity. The proposal minimises investment risk for the wind farm operator, but does not address the far more often occurring curtailment due to network congestion.

Curtailment data for a number of network regions can be retrieved from the operator of the 110 kV grid in the North Sea coastal region with high wind penetration (eon Netz GmbH). It shows that congestion occurs mainly at this voltage level. During 2010, only 10 instances of curtailment are reported due to restrictions at higher voltage levels and only one instance due to congestion at lower levels.

Fig. 5 displays the number of hours with curtailment to a certain level in 2010. The regarded grid in Northwestern Germany is subdivided into several curtailment zones at the 110 kV voltage level. Forty-three per cent of all curtailments in Germany occurred in this grid during 2009 (Bömer et al., 2011), which is why it is in the focus of this analysis. The figure shows the number of events in a specific hour, e.g. curtailment to 60%, 30% or only 0% of capacity as well as when curtailment was finished (i.e. 100% permitted again). The maximum curtailment in one of the sub-zones is taken as the basis for calculation of the figure. It is clearly visible that a disproportionally large amount of curtailment activation falls into the afternoon hours, followed by a high number of ended curtailments in the early evening hours. This reflects the diurnal wind pattern where afternoon generation exceeds night generation by 20%. The average duration of aggregated curtailment of all zones is at 5–6 h. The distribution of curtailment is not even between the regarded zones: in a few zones, slight curtailment occurs only in few hours a year, while the most heavily affected zone is subject to 480 h with full curtailment down to 0% in 2010. For the respective wind farm operators, compensation payments can therefore be expected to comprise a considerable share of their income. The share of curtailed wind generation in Germany was at about 0.2% in 2009 (Bömer et al., 2011). Despite the efforts of network reinforcement, the curtailed amount cannot be expected to decrease substantially due to new wind installations and repowering of older units. Fig. 6 shows wind generation in all hours of the year in the Tenne T control zone in Germany and hours subject to curtailment during 2010. The high number of curtailment hours

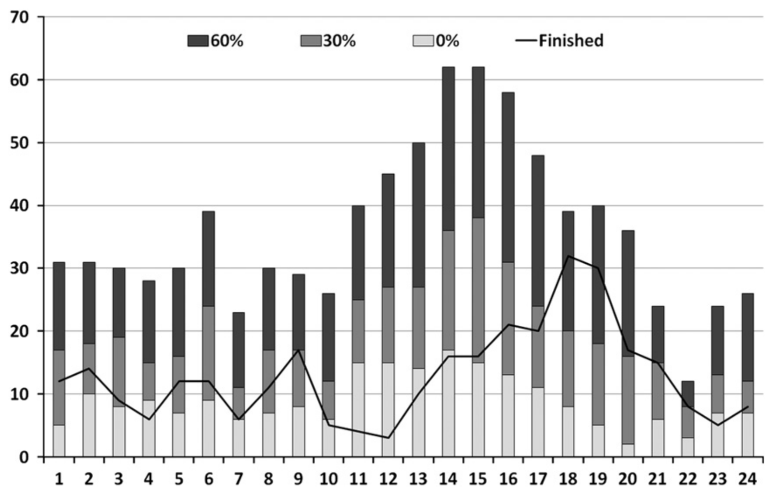

Fig. 5. Number of hours when curtailment to a certain level was effectuated in Northwestern Germany (eon Netz GmbH), 2010.

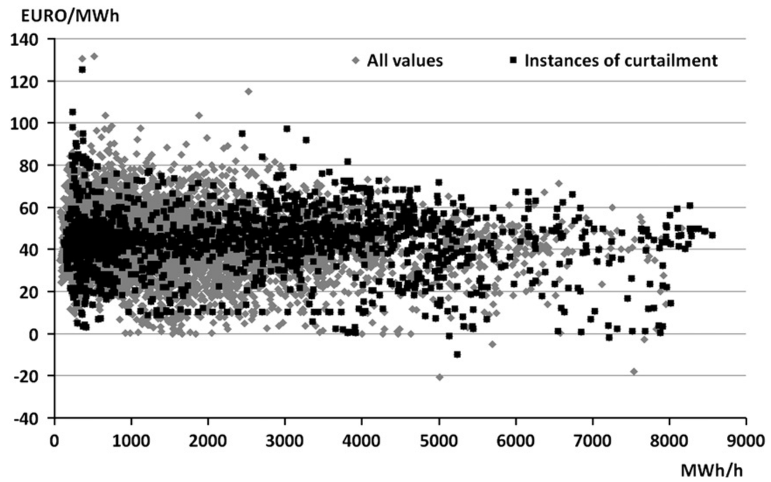

Fig. 6. Wind generation in the German TenneT area and respective electricity prices, 2010—all hours and hours with curtailment.

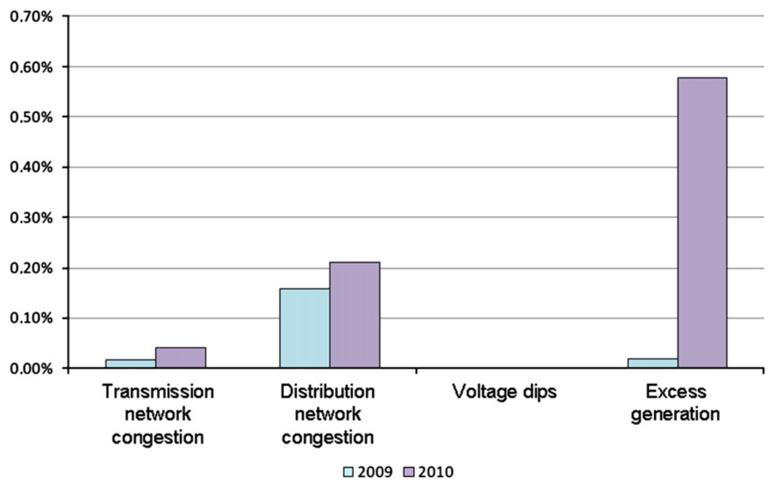

Fig. 7. Share of MWh curtailed in Spain. 2010 values cover the time period until 30/09/2010 (Duvison García, 2010).

even at low wind generation in the control zone illustrates that curtailment is a highly local issue. Thus, curtailment is independent of overall wind generation; the average value of wind generation and the average value of curtailed wind are similar. However, both are lower than average market prices due to the merit-order effect. In conclusion, curtailment in Germany happens predominantly involuntarily and because of network congestion at the 110 kV voltage level. Generators are to be compensated in this case, whereas they receive no payments if the generation reductions were due to concerns about overall system stability. This provides comparatively stable investment conditions for RES operators, but locational incentives are rather limited and only due to facing the risk that not the full foregone production amount is compensated for. With Germany progressing towards a voluntary price premium scheme from 2012 onwards, the authors expect that the involuntary curtailment presented here will be partially replaced with voluntary curtailment.

4.2. Involuntary curtailment in Spain

Involuntary curtailment in Spain is categorised according to the following reasons: transmission network congestion, distribution network congestion, voltage dips and excess generation. The last point is more severe in Spain than in a number of other European countries due to the comparatively weak interconnections of the Iberian system with France. A minimum share of conventional generation necessary for system stability is determined by the TSO and wind generation affecting this minimum share may be curtailed. Revuelta (2011) gives an example where this minimum share exceeds 10 GW, corresponding to more than 1/3 in single hours. Between 2008 and 2010, total curtailment varied between approx. 70 and 250 GWh (Duvison García, 2010). However, the reasons changed considerably: voltage dips were the main reason in 2008, followed by congestion at the transmission level, while distribution congestion and excess generation played only a minor role. This picture changed in 2009 and 2010, when distribution congestion and excess generation, respectively, were the main reasons. This is illustrated in Fig. 7, and the share of MWh curtailed in the first 3 quarters of 2010 adds up to approximately 1% of possible generation. For 2020, the Spanish TSO expects a curtailment of 3.6 TWh/year, amounting to about 5% of possible wind generation (Duvison García, 2010).

If the curtailments were announced before the closure of the day-ahead market, no compensation is given. Later restrictions are remunerated at 15% of the spot market price without the feed-in premium (Rogers et al., 2010). In conclusion, the reasons for curtailment changed over the last years, with excess generation concerns being the main reason in 2010.

4.3. Voluntary short term curtailment and market prices—incentives and indications

Voluntary curtailment appears in the price duration curves as illustrated in Fig. 3. The flat parts at zero or negative prices reflect a marginal technology with identical costs, e.g. wind that receives a production subsidy. The flat parts might also include hours where other technologies are marginal at the same level. The case of Texas, 2009, illustrates this where curtailment due to grid constraints reduces the voluntary curtailment seen in 2008 (value of production tax credit, see Fig. 8).

Examining market prices in Western Denmark in 2010 (Fig. 9) reveals that only very few hours show zero prices and that there is no negative price level reflecting the feed-in tariff or premium level. In the future with much more wind capacity in Denmark, the flat part at zero price is expected to cover a larger number of hours.

The illustration of up and down regulation prices over a period of 3½ years in Fig. 10 reveals that up-regulation prices are higher and that the duration curve for down regulation contains more hours with low and even negative prices. The two curves do not correspond in time along the x axes, but as duration curves. The up regulation curve is steeper than the down regulation curve for high prices and flatter than the down regulation for low prices. This suggests that the asymmetry between balancing costs will be most pronounced at high and low prices and much smaller for the majority of hours in the middle. Incentives for voluntary curtailment will thus be most pronounced in the high price and low price areas.

5. Discussion: what are the economic costs and benefits of curtailment?

An obvious policy ambition is to achieve a level of curtailment that balances social benefits with costs. This will require that costs and benefits can actually be assessed. We have identified categories of curtailment in Table 1 which can all contribute to

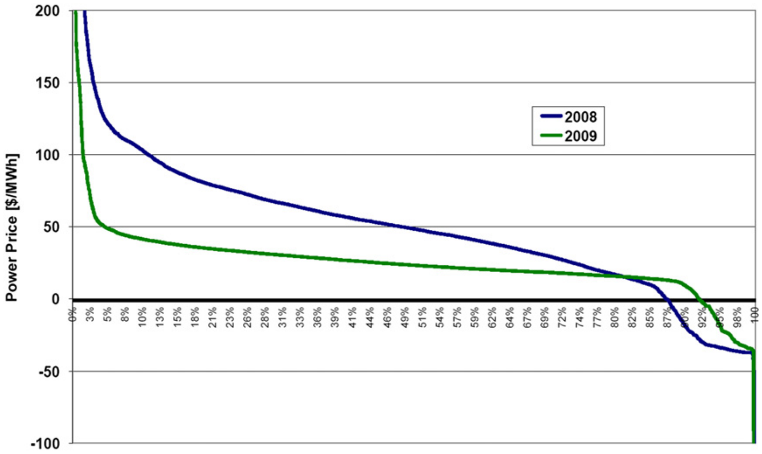

Fig. 8. Price duration curves for Texas indicate voluntary curtailment at negative price levels (reproduced from Nicolosi, 2010).

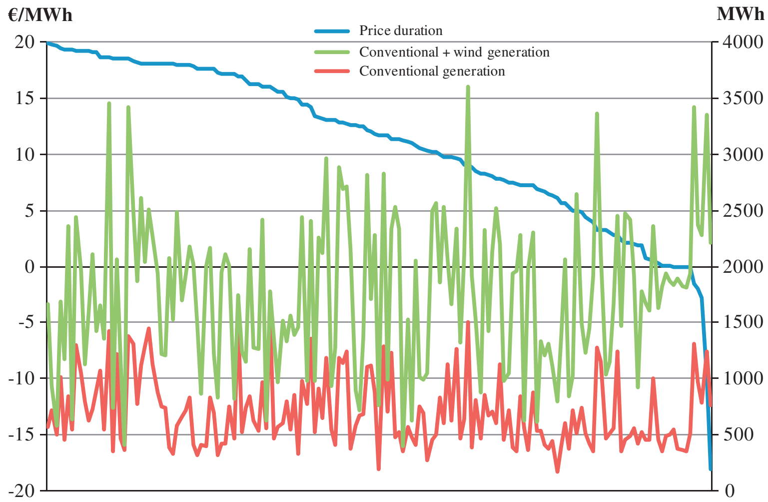

Fig. 9. Price duration curves for Western Denmark in 2010 indicating a small amount of voluntary curtailment at zero prices (165 lowest price hours, sorted according to the price duration curve).

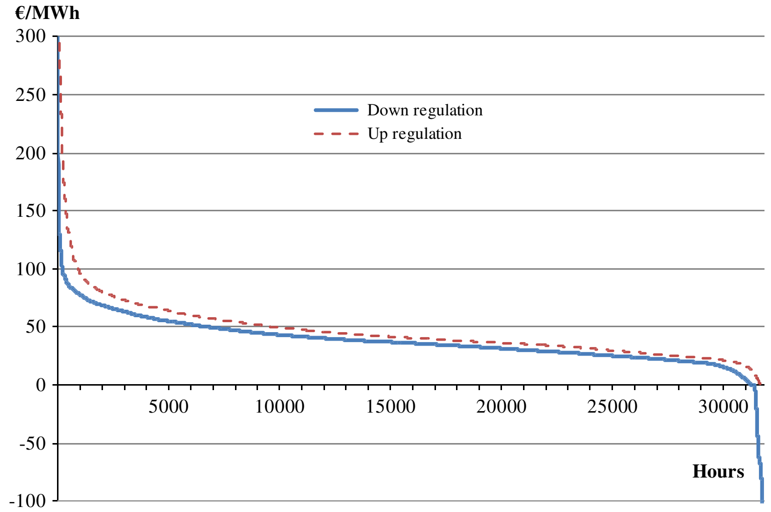

Fig. 10. Duration curve for hourly up- and down-regulation prices in West Denmark, June 2006–December 2009.

total optimal curtailment. Some of these will be partly overlapping, but in general they occur at different times. From a theoretical perspective, curtailment should take place up to the point where the marginal cost of avoiding this curtailment equals the marginal value of spilled energy, but both the marginal costs of avoiding and especially the value of the spilled renewable generation is difficult to quantify.

The private cost of curtailment depends on the support scheme generators are entitled to, specific rules regarding curtailment and compensation and possibly the power market price. Compensation could be granted based on escaped income or the marginal value of the generation. In the first case, the specific compensation rate is constant under a feed-in tariff scheme and price-dependent under premium and TGC schemes. In the latter case, it always depends on market prices.

If income is only based on power market prices, higher curtailment rates are acceptable. In this case, the implicit incentive for wind investment is lower than if additional income from a support scheme is taken into account as well. Granting support compensation may be based on the criterion of the replaced marginal technology, i.e. only if CO_2-emitting generation is replaced and thus, one of the goals of the support scheme is achieved. If this criterion is applied or the subsidy beyond market prices is not compensated for at all, the incentive to invest in fluctuating RES is decreased.

Socio-economic benefits of allowing curtailment amount mostly to avoided investment costs and avoided operational costs. Avoided investment costs are mainly associated with not building additional grid capacity only needed for a few hours annually. Avoided operational costs cover lower systems reserves procurement as well as buying less regulating energy from partly inflexible conventional units. Furthermore, reduced adjustment costs in case of emergency faults as well as the expected value of avoided consumer disconnexions account as avoided operational costs.

In practice, optimal socio-economic curtailment is expected to be rather low (max. 1–2% of possible generation) even in grids with relatively high shares of fluctuating generation. Grid constraints curtailment would involve very few distribution grids in Denmark—the grids with high generation to load levels are few and capacities in general high. Higher levels of optimal curtailment might be determined if a connexion is erected exclusively for one project and the connexion investment amounts to a considerable share of the RES project investment. This is typically the case for offshore wind farms. For the UK, it is estimated that dimensioning the offshore wind farm on average at 112% of the installed generation capacity leads to an optimal result (National grid, 2009).

6. Concluding remarks

This article analyses a number of different constellations leading to involuntary and voluntary curtailment. Curtailment can be a rational option to deter generation investments where grid integration costs are very high, or simply to avoid high grid investment cost by accepting a marginal curtailment (loss) of generation when we are expanding the renewable fluctuating generation capacity. Accepting this approach can lead to a more cost-efficient deployment and system integration of RES generators. Avoiding curtailment completely would make it extremely expensive to reach a high share of fluctuating renewable generation. Ideally curtailment should take place up to the point where the marginal cost of avoiding this curtailment equals the marginal value of spilled energy. We find that both in the short and the long run situation curtailment can be an optimal solution. The short and the long run optimal levels of curtailment will normally differ due to time delays in adjusting capacity, lumpiness of network investments and changing conditions regarding reliability and system security.

Efficient levels of infrastructure investment with fluctuating generation depend on the marginal grid costs and these differ strongly between areas and between on-shore and off-shore grids. Naturally, this should affect the optimal level of expected curtailment in the areas, with less grid capacity off-shore and more expected curtailment as well. This involuntary curtailment should be a regulated option that compensates the generator at least corresponding to the market price of electricity.

Efficient location of new capacity within a market is accomplished with DSOs providing incentives for generators to invest, where integration costs are the lowest—if grid capacity is a constraint, costs in terms of risk of curtailment loss should be included in the investment localisation decision.

For the regulatory policy the recommendation is thus to allow curtailment by DSOs or the TSO, but the question is whether to compensate generators at their full income, i.e. including support, or at market prices. A compensation at the level of the market price secures incentives for DSOs to invest in grid capacity up to the point of expected costs of curtailment under a regulatory regime that leaves this decision to the DSO. At the same time, the expected loss from incomplete compensation would assure that investors locate their investment, where the least curtailment is expected. Compensation regulation exists in some markets such as Germany, but rules differ among markets.

The authors expect that curtailment will be highest in association with offshore wind, where connexion costs are high. In the future, an increasing share of connexions will be off-shore and the investment in connexion capacity should assure that there will be less than full capacity for these. Total curtailment is low in most markets, but rising with RES shares and in some regions as in the German example can be substantial. For Denmark the curtailment is very modest with less than 0.5% of annual production hours affected corresponding to around 0.1% of total fluctuating generation. Emergency curtailment is very modest in DK as the interconnection capacities are very strong and the very huge disconnexion of wind turbines in short time happens very rarely. Also the introduction of negative prices has contributed to reduced supply from conventional generation in the relevant hours.

An opportunity for the least-cost integration of renewable generation can be achieved by envisaging curtailment where, until today, connexion of renewable generation takes place at nameplate capacity. For example, additional offshore wind farms could be installed at existing sites without major transmission grid reinforcement if curtailment was allowed. Existing or planned installations in a number of countries like Germany and Denmark could be extended by 10–15% of installed capacity by aiming at optimal curtailment as was concluded in the UK study.

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– Appendix VIII –

Power market design choices: optimal timing for wind energy

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Power market design choices: optimal timing for wind energy

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ABSTRACT

Today's spot power markets' timing structure in Europe developed according to a diurnal pattern. It leaves sufficient time between market closure and the first hour the market refers to. This reflects mainly the requirements of large-scale thermal power plants. With the increasing share of renewable energy sources, adjusting the spot market's timing to account for their requirements should be considered. The main option discussed is a later gate closure, though this is not the only option. This study presents a conceptual analysis of the different options, namely later gate closure, shorter trading periods and a phase shift of the whole trading process. Shorter gate closure corresponds to a case where multiple spot auctions take place per day, e.g. always 6 hours before the first delivery hour. A phase shift means that the 24-hour-pattern is maintained, but differs from full calendar days. All of the analysed exemplary quantitative case studies yield positive benefits, though their magnitude differs. In general, minor changes as a phase shift result in smaller benefits than larger changes as shortening the trading period.

1 INTRODUCTION

Today's power market design in Europe consists of the following successive markets: day-ahead spot auctions, mostly bilateral intraday trading and final balancing and regulating of remaining deviations. This market design structure has been developed chiefly for existing structures, with a strive towards implementing intraday markets in the last years. The history of European liberalised power markets starts in 1971, when the predecessor of Nord Pool Spot was launched as a system to optimise the dispatch of hydro reservoirs in Norway. Assuring electricity system stability calls for ahead-planning and dispatch instead of real-time markets. Day-ahead planning – i.e. the unit commitment and dispatch planning the day before delivery – evolved traditionally for practical reasons as it is in line with the daily pattern of decision makers. After the liberalisation of Europe's national electricity markets around the turn of the century, competitive national day-ahead markets were established in a first step. Successive developments, though at a different pace in different countries, are national intraday markets and the harmonisation of markets, especially market mechanisms and timing, across borders. Using the electricity exchange for trading is not mandatory, which is why their product design has to be beneficial for market actors in comparison to bilateral over-the-counter trading. The single exchanges are either owned by a number of electricity market actors or by financial institutions like commodity exchanges. They are primarily regulated by supervisory bodies for financial institutions and abide to general commodity exchange rules, whereas their product range, design and fees are at their discretion (though influenced by regulator's positions). In practice, this leads to a product portfolio that is based on well-established historical products and new ones that are designed in cooperation with market actors and energy regulators. The probably most important development for the integration of wind energy in power markets during the last years is shortening the gate closure on intraday markets. This allows for correcting prediction errors until very shortly before delivery without being exposed to the higher imbalance charges. [1] provides the first in-depth analysis of the value of intraday markets for wind power. This has since been which has since been complemented notably by [2], who analyses existing intraday markets. From a private-economic perspective, [3] optimise selling wind in power markets. The latest relevant publication is [4], giving an overview of current intraday and balancing market designs as well their possible international integration. The last aspect has in addition been analysed with a North European case study [5], quantifying possible benefits of cooperation. Moreover, [6] systematise imbalance types and their attribution to different reasons and actors.

To the authors' knowledge, the impact of general power market design on achieving EU goals for sustainable energy – such as a 20% generation share by 2020 – is a hitherto underestimated research field. While [7] provides a general overview of wind integration options, latest works regarding market design comprise [8], dealing with power exchange incentive structures, and [9] as well as [10], which focus on transmission capacity allocation and pricing for the efficient integration of RES-E. An ongoing EU-funded project is OPTIMATE, where a model of the West European electricity sector will be able to reflect changes in electricity market design (www.optimate-project.eu). When selling wind energy in liberalised power markets, actors face the choice between a) selling it day-ahead and correcting deviations in intraday markets or b) selling it directly in intraday markets when the prediction error is lower. Option a) is compulsory in some countries, e.g. in Germany for all the wind power receiving the feed-in support scheme. Accepting the day-ahead market as the main and most liquid market, both options lead to suboptimal unit commitment and dispatch planning that comes at a cost for the overall system. In case a), this is aggravated by additional transaction costs. With the increasing share of electricity from renewable energy sources (RES-E), the importance of a power market design that is reflecting the needs of fluctuating resources while ensuring overall system reliability is not diminished. The current research gap consists in a conceptual analysis of power market timing choices and how they can contribute to facilitate the integration of renewable energy sources. This study analyses different timing options of the main ahead market (which is not referred to as the day-ahead market in the following because this term represents the existing benchmark situation).

The remainder of the paper is structured as follows: first, we describe different possible concepts of modifying the timing of the main ahead market. They cover a later gate closure time, a shorter main market period length (i.e. shortening the reference period from 24 to e.g. 12 hours) and shifting the whole trading process by some hours. Notably, the presented options do not cover longer planning horizons as an option. It is assumed that only a system with shorter timing, reflecting a more flexible system with a larger share of fluctuating RES-E, possibly offers improvements. Second, the quantitative model for the assessment of the different options is addressed. Third, we present exemplary quantitative results before turning to the final discussion and conclusions.

2 CONCEPTS – TIMING OPTIONS

Several timing aspects could be altered in power markets. This section provides an overview of the different possibilities. A more elaborated version can be found in [11].

Figure 1 gives a conceptual overview of the main time determinants in power markets. The illustration is based on the current status in most European power markets. Demand needs to be covered over one day, reaching from hours α to β (typically 1 to 24). This is the *trading period length*. The other main time determinant is the *gate-closure horizon*: it is the distance between final submission of all bids at the power exchange and the first hour of delivery. Another aspect illustrated in the figure is that forecast errors from variable RES-E generation (ΔRES-

E) increase with time distance. For wind power, quantifications of this effect for wind power can be found in the literature review by [12] or in [13].

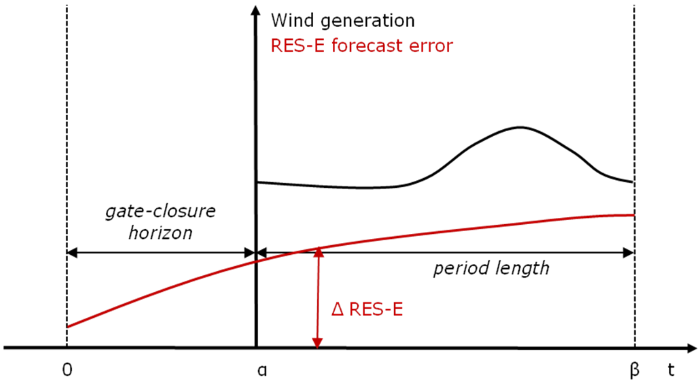

Figure 1: Time determinants in power markets

2.1 Changing the gate closure horizon

Figure 2 shows the effect of shortening the day-ahead gate-closure horizon. In practice, this corresponds to having the gate closure in the afternoon or evening hours instead of at noon. The point in this context is that a shorter gate-closure horizon will decrease the consequences of forecast errors. With regard to wind energy, this argument has been discussed and quantified [1]. The introduction of intraday markets during the last years has certainly reduced this effect. Nevertheless, all intraday corrections are associated with transaction costs and possibly other market imperfections [14]. Changing the gate-closure horizon remains therefore a reasonable measure to consider. Obviously, this has an impact on power plant operator's planning, as a shorter gate-closure horizon might have a negative impact on unit commitment and dispatch decisions if the power system covers slowly reacting units. Additionally, the costs of keeping a unit in standby mode from the end of a trading day until the following gate closure could increase.

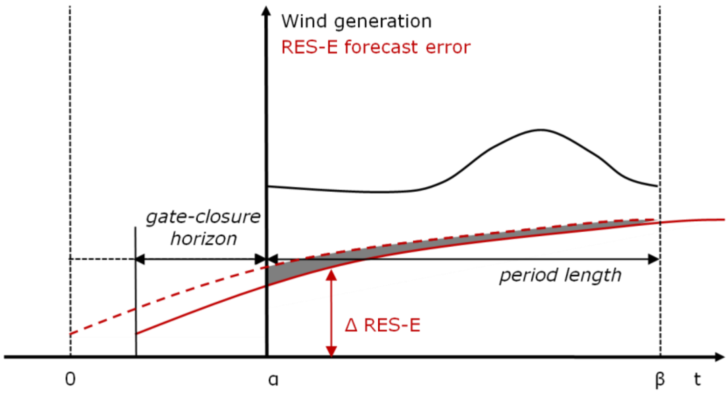

Figure 2: Time determinants in power markets - Changing the gate-closure horizon

2.2 Changing the trading period length

Another proposed measure is the shortening of the trading period length, as illustrated in Figure 3. In the graphical example, the trading period length is cut in half (12 hours). Keeping a gate-closure horizon of e.g. 12 hours, this means that at 12am, the 12 hours from 12pm are scheduled and vice versa. In comparison to the base case, where the period reaching from 12 to 36 hours ahead is computed, this offers the advantage that forecast tools only need to provide reliable results for a shorter time horizon. Instead of 36 hours, the maximum look-ahead time is now reduced to 24 hours. This in turn leads to a lower adjustment requirement due to the shortened look-ahead time as sketched in the figure. For slowly reacting thermal units, the unit commitment decision could be impacted because startup decisions are based on a shorter period length. The magnitude of this effect depends on the unit commitment and dispatch assumptions for the thermal units in the system.

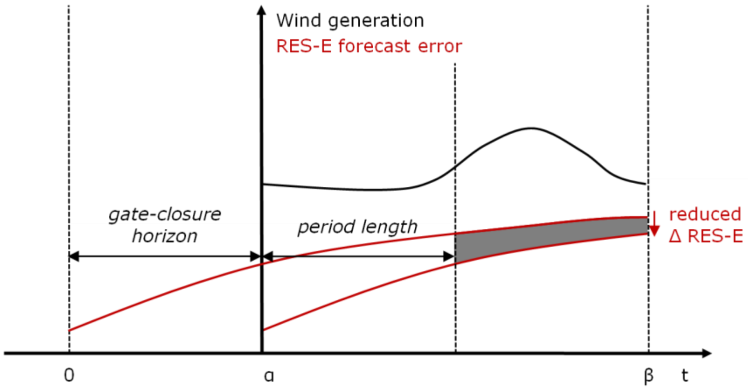

Figure 3: Time determinants in power markets - Changing the trading period length

2.3 Shifting the trading period

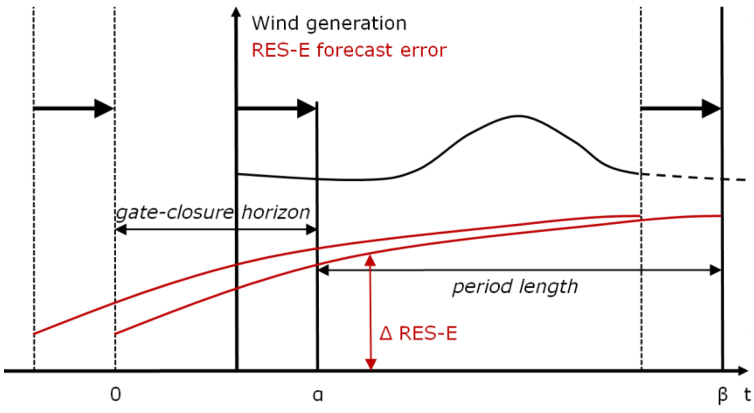

Figure 4: Shifting the trading period

Figure 4 is a more complex picture than the previous ones. Instead of shortening the gate-closure horizon or trading period length, these two are merely moved – the whole market is subject to a phase shift. As an example, a trading period length could reach from 6am to 6am, instead of being identical with calendar days. The gate-closure time could be moved analogically, e.g. from 12pm to 6pm. The effect is primarily similar to shortening the gate-closure horizon: the daily peak of wind generation and the associated forecast error are moved closer to the gate closure. In return, hours with less wind production – and therefore an overall lower forecast error – are moved to the end of the period length. For these reasons, moving the whole trading process could be advantageous for RES-E: the financial consequences of adjusting forecast errors are reduced because the whole period is moved. Unit commitment and dispatch decisions of non-fluctuating units remain as they are today; the trading process is merely shifted by a few hours.

3 MODEL

3.1 Assumptions

In contrast to the common assumption of perfect markets, we assume that intraday markets cannot capture all corrections in a cost-neutral way. This leads to the ambition that the main market should be able to match RES-E and thermal generation in a least-cost way from a system point of view. Following intraday corrections are cheaper than paying ex-post balancing fees, but still associated with flexibility costs.

[14] argues that it is beneficial to have ahead-markets instead of real-time markets only. The reason is the possible exercise of market power by provoking scarcity rents. If several market participants commit to delivieries in an ahead-market, this possibility is reduced. Together with the fact that today's West European markets enjoy a certain trust among their participants, this paper only regards changes in timing. Changes in the general structure of an ahead-auction with a following intraday market are not discussed in this paper.

The principle of participating voluntarily on electricity exchanges, in contrast to pools, makes it desirable to have an attractive market design for all market participants. This comprises financial actors that improve the liquidity especially in intraday markets. In most European power markets, more electricity is traded via bilateral over-the-counter trades than via power exchanges. Therefore, we assume that transaction costs of market participants due to adjusting to a changed timing structure are limited as they could switch to bilateral contracts.

Flexibility costs are defined as Transaction costs + Costs of inefficient unit commitment. The reference case for flexibility costs is defined as a gate closure horizon of 12 hours and a period length of 24 hours. If everything (including demand, outages, etc.) was perfectly known in advance, flexibility costs would not play a role. If, however, new information arrives over time, this may lead to a certain demand for flexibility. Then, it is critical to efficiently reconcile the demand for that flexibility with the limited, costly flexibility of the thermal production environment.

For the case of electricity production from wind, the forecast error rises proportionally with power production. In the short term, this argumentation is doubtful due to the shape of the typical power curve of a wind turbine. In the long run and working with averaged or aggregated data, it is a valid approximation.

All changes to the time structure should be based on full hours and such that an overall daily pattern can be kept. In other words, if the period length is shortened to t hours, $t*N$ is equal to 24.

The power market timing should be optimal in the long run. This criterion excludes the possibility of seasonal adjustments to the power market design due to seasonally different variations in RES-E generation.

Finally, it is assumed that meteorological updates and related power production forecasts are updated on an hourly basis. All wind power generation is bid into the ahead-market and errors are corrected afterwards at the respective flexibility costs.

3.2 Data

The following analyses are based on specific set of data and associated assumptions. The daily wind production profile corresponds to the average, normalised profile in West Denmark over a period covering several years. The forecast error (N-RMSE) over time is displayed in Figure 5 and based on the current forecast quality used at EnBW TSO. It thus reflects a typical countrywide forecast error curve (see [16] for a literature survey on wind forecasting). The error is given as normalized root mean square error (N-RMSE, also R-RMSE for 'relative'). The N-RMSE is defined as the root of the average, squared absolute forecast errors divided by the total generation capacity. The other graphs in the figure display examples of flexibility costs in different power systems. If information is known correctly 37h ahead and enters today's day-ahead market, no flexibility costs are associated with it. For all adjustments closer to real time, flexibility costs apply. Five different examples of flexibility costs are assumed: an inflexible system system with high or low costs. The term inflexible describes the property that costs are increasing towards real-time over the whole regarded period. This reflects possible inefficiencies due to wrong unit commitment and dispatch of large thermal units. By contrast, the flexible systems with high or low costs exhibit rising flexibility costs only before the last few hours before real-time. The fifth system is a fully flexible system where flexibility costs are constant and equal to transaction costs over all hours. A large 100% hydro reservoir system could correspond to this concept if there is excessive capacity because only shadow water values are altered marginally through balancing purposes. This, of course, is a best-case assumption; for a quantitative study on the relationship between spot and balancing prices in an existing hydro system, see e.g. [17]. Flexibility costs of existing power systems are hard to determine and depend strongly on decision-making process assumptions. The five cases constitute illustrative examples. Newly erected and planned thermal units have far faster startup and modulation characteristics than their predecessor generation. Additionally, coal and nuclear units tend to be replaced with gas-fired power plants which are more flexible. These developments correspond to the change from an inflexible to a flexible system in our concept.

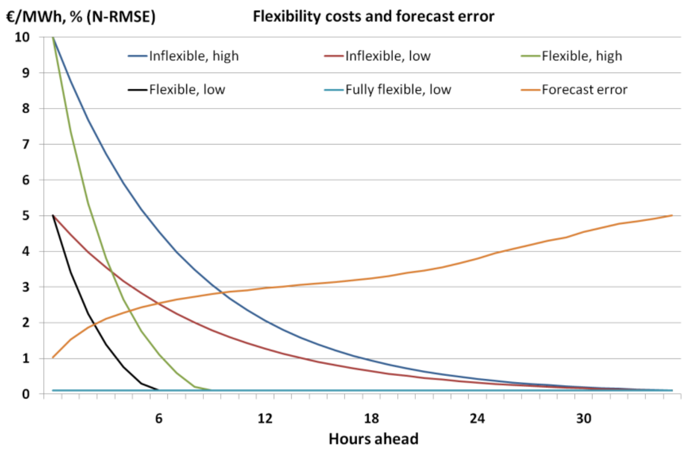

Figure 5: Flexibility costs of different scenarios and forecast error

3.3 The pricing of forecast errors

The starting point of the model is that 1 MWh of forecast error in the benchmark case (12h of gate closure horizon, 24h period length) needs to be corrected. This happens with the improved forecast over time. Thus, about 80% of the forecast error can be corrected until one hour before delivery. Let *a* be the forecast horizon, i.e.

hours to delivery. The share traded *h* hours ahead is identical for all hours of the gate-closure horizon. The underlying idea for this is that the forecast error that can be precised *a* hours ahead is constant – the error that can be corrected e.g. 1 hour ahead is indifferent of the market design. For the hours beyond the gate-closure horizon, the amount to be corrected (Q_{corr}) equals

$Q_{corr}(h) = [FE(h-1) – FE(h)]* HW(h)$,

where FE denominates the forecast error at different times and HW is the normalised hourly wind generation of the reference hour. HW is the hourly wind generation of the reference hour: assume that hour no. 1 of a day is 8.9% below the average daily production, whereas hour no. 13 is about 14.4% above the average daily production. Following this argumentation, the forecast errors that can be corrected 13 or 25 hours ahead, respectively, vary by these factors. In a second step, these hourly amounts to be corrected are multiplied with the flexibility costs (FC(h)) of the different scenarios and set in relation to the benchmark case. This yields the resulting savings for wind power generation:

$$Savings = \frac{\sum_{h=0}^{\beta} Q_{corr}(h) * FC(h)}{\sum_{h=0}^{\beta=36} Q_{corr,benchmark}(h) * FC(h)}$$

This model is applied to the different concepts described above. Results are described in the following.

4 RESULTS

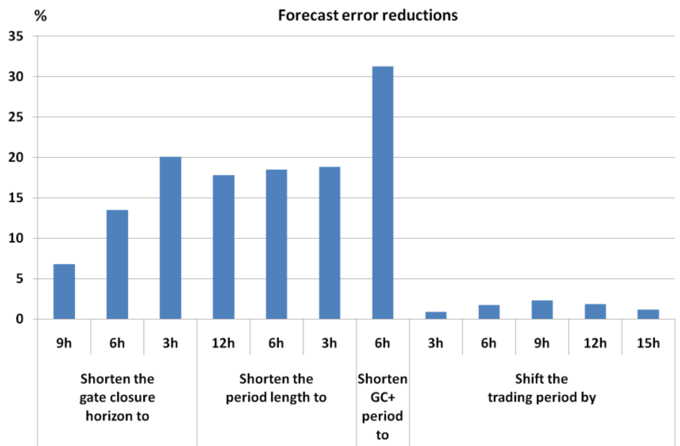

Figure 6: Forecast error reductions for different timing options

Figure 6 displays the forecast error reductions through market design changes in comparison to the benchmark case. Shortening the gate closure has a considerable effect. Due to the fact that a large share of forecast errors lie within the first hours, shortening the period length does not have such a pronounced effect: the forecast horizon is limited to 24 hours under a period length of 12 hours and to 18 hours under a period length of 6 hours. A special case is the combination of both options, i.e. shortening both the gate closure horizon and the period length to 6 hours. As a result, the maximum relevant forecast error corresponds to 12 hours ahead. This yields a reduction of more than 30%. In comparison, the benefits of shifting the trading period are small: the peak is at 2.3% for a shift by 9 hours.

Table 1 shows the savings that can be achieved due to changes in market design for the different assumed power systems and their associated flexibility costs. Shortening the gate closure horizon gives balancing cost reductions between 0.15 and 4.34% for all power systems except the fully flexible one. For the fully flexible system, the possible savings are identical to the physical amounts (forecast error reductions) discussed above. Shortening the period length leads to improvements that are roughly comparable to shortening the gate closure horizon to 6 hours. Notably, the differences between shortening the period length to 12 or 3 hours are quite small. An exemplary combination of both concepts, shortening the gate closure horizon and the trading period to 6 hours, corresponds to holding an auction every 6 hours for the period of 7-12 hours ahead. It leads to higher benefits in all cases, especially in an inflexible power system. Finally, shifts in the trading period result in improvements of about 0.2-0.3% in the inflexible power systems, 0.05-0.1% in the inflexible systems and 2.3% in the fully flexible system.

Table 1: Savings for wind energy balancing through changes in market timing in per cent (relative to benchmark case)

Power system, flexibility costs		Inflexible, high	Inflexible, low	Flexible, high	Flexible, low	Fully flexible, low
Shorten the gate closure horizon to	9h	0.67	0.90	0.15	0.32	6.77
	6h	1.72	2.21	0.32	0.63	13.47
	3h	3.56	4.34	0.75	0.99	20.09
Shorten the period length to	12h	1.49	2.09	0.39	0.84	17.81
	6h	1.43	2.04	0.41	0.87	18.49
	3h	1.51	2.14	0.41	0.89	18.85
Shorten gate closure + period to	6h	6.45	7.84	0.91	1.47	31.23
Shift the trading period by	3h	0.05	0.08	0.02	0.04	0.87
	6h	0.12	0.17	0.04	0.08	1.72
	9h	0.19	0.27	0.05	0.11	2.30
	12h	0.19	0.26	0.04	0.09	1.86
	15h	0.15	0.20	0.03	0.06	1.18

5 DISCUSSION

The results presented above illustrate that changes in market design could lead to reduced balancing costs for wind power. They are exclusively from a wind power perspective and calculated with an average production series from West Denmark. With the ongoing integration of European power markets, a common timing structure for all markets is required, so spatial effects and technological differentiation between countries should be taken into account before drawing policy recommendations. More precisely, it would be appropriate to regard the daily RES generation patterns of all countries – most importantly wind and solar generation – and compare it to regional flexibility costs. Flexibility cost depend on the remaining generation structure. The concept of flexibility costs used in this paper is hard to estimate from existing power markets with existing models. First, the existing market timing structure is a fundamental assumption in these models and hard to alter. Second, the results are depending on the assumptions made for unit commitment and dispatch. If large thermal units are for example defined as always running, changes to the gate closure horizon or period length will not have an effect on their unit commitment. If a large unit's commitment decision is made based on its long upstart time and a short-term power market, it might not operate and this decision could increase system costs. Let us assume that the current timing structure with a gate closure horizon of 12 hours and a period length of 24 hours is useful for the operation of existing thermal units. First, the share of RES-E – and their share of balancing cost of total system costs – is increasing and they are partially replacing existing units. Second, a number of the existing units is progressively replaced with faster-reacting gas-fired units. Third, new large-scale thermal units offer significantly faster startup and modulation characteristics [18]. This means that the value of the prevailing timing structure will decrease. In other words, this development starts out at an inflexible system with high flexibility costs. If unit commitment decisions for slowly reacting units and block bids over a number of hours still play a role in the changed system, it corresponds best to the inflexible system with low flexibility costs. If all units in the system can start and stop quickly with low costs, the flexible systems correspond best to the future situation. The fully flexible system can be described as a system of fluctuating RES-E and hydropower reservoir units only. Day-ahead market signals do not offer any major benefits for the market participants in this case, apart from daily optimisation of storage units as e.g. pumped hydropower. However, the basic assumption is that fluctuating RES-E units bid their expected generation into the ahead-power market and correct fluctuations afterwards. This assumption does not hold for the fully flexible system and for the time horizon of flexible systems where flexibility cost is identical to transaction cost. If there is no cost associated to bidding at a later point in time when the forecast error is lower, there is no reason to bid in ahead-markets. For this reason, the comparatively large benefits displayed in Table 1 for the fully flexible system would not materialise in reality. The presented study presents nevertheless a novel approach to power market design and could therefore in future work be extended both geographically and technologically to achieve more realistic results. The two predominant RES technologies in Europe, wind and solar power, share common characteristics with regard to forecast errors. In comparison to wind power forecasting, solar power forecasting faces a development lag to due to the later deployment of the technology. Exemplary solar power forecast error quantifications are e.g. given by [19]. The proposed methodology thus can reflect the main technologies to be accounted for.

6 CONCLUSIONS

This paper looks at a number of options to change the timing of the day-ahead market: shortening the gate closure horizon, shortening the trading period and shifting the existing market by a number of hours. If all wind power is sold in the ahead-market and needs to be corrected afterwards, the possible reductions are most distinct in the cases where the market length is reduced considerably. Such measures would however have serious impacts on the scheduling of thermal units.

The existing power markets are voluntary and well-functioning; all changes to them should only be done cautiously and after detailed analyses. Changing the gate closure horizon and/or the period length are major changes that are not suggested in the short run, but might be worth a more detailed analysis in the long run. Shifting the trading period could reduce the amount to be balanced by 2.3% by moving the daily wind power production peak closer to real-time. However, the financial consequences are limited to about 0.3% because the respective hours remain distant to gate closure. It is estimated that these numbers indicate the lower limit of possible savings for the power system, without regarding costs caused by shifted working hours on energy trading floors. In principle, the same argumentation applies to PV generation, where the variation between day and night is even stronger. Temperature-depending electricity demand might also be forecasted slightly better if the trading process is shifted by a few hours and therefore, gate closure and the daily demand peak get closer to each other.

Due to the large share of slowly reacting thermal units in Europe, it seems reasonable that the costs associated to shortening the gate closure horizon and/or the period length would exceed the discussed gains due to reduced balancing costs. This might change in the long run with an increasing share of fluctuating RES-E. In the short-term, shifting the trading period seems a more balanced option. Gains due to reduced balancing are very limited, but costs on the side of thermal units and their market processes are as well. The main costs associated would be to pay employees for working at different times of the day. Interactions with other relevant markets as e.g. daily routines of the gas market could also play a role. In conclusion, this paper presents novel options of ahead-market design modifications. In the long run, adapting the market design to the growing share of wind power and other fluctuating RES-E as solar power might be beneficial. In the short run, shifting the trading process and period by a number of hours is an option that seems worth for further analysis. This option should be seen independently from other discussed modifications, e.g. a later gate closure of intraday markets or reshaping price zones, which should not be neglected.

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Offshore grids between several countries combine the absorption of wind energy with international power trading. As the topic has mostly been analysed with a focus on topology and technical issues until now, market-operational questions in offshore grids and investment implications under different regulatory frameworks are a hitherto underrepresented research field. This cumulative PhD thesis addresses these issues. It is composed of a generic part and eight papers. Covered subjects include the choice of support mechanism, price formation in single price zones, corresponding investment incentives, possible strategic behaviour as well as the question of balancing wind forecast errors in offshore grids.

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